STAFF WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	
Preparation of the 2007 Integrated Energy Policy Report (IEPR)	
Staff Workshop on Transportation Energy Demand and Import Infrastructure	Docket No. 06-IEP-1B

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, MAY 8, 2007

9:09 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

John L. Geesman

ADVISORS PRESENT

Melissa Jones, to Commissioner Geesman

Kevin Kennedy, to Commissioner Jeffrey Byron

Susan Brown, to Commission James Boyd

STAFF PRESENT

Lorraine White

Jim Page

Malachi Weng-Gutierrez

Gordon Schremp

ALSO PRESENT

Mike Eaves
California Natural Gas Vehicle Coalition

Jane Turnbull
League of Women Voters

Barbara Fry
ARB

Jay McKeeman
CIOMA

David Hackett
Stillwater Associates

Gina Grey
WSPA

Jim Larson
Pacific Gas and Electric Company

Dwight Stevenson
Tesoro

ALSO PRESENT

David Wright
Plains All American Pipeline, L.P.

Jeremy Cuisimano
USDOE

I N D E X

P R O C E E D I N G S

9:09 a.m.

MS. WHITE: Welcome, everyone. Today, we're having a staff workshop on the transportation energy demand and the import infrastructure requirements. This workshop is a part of the 2007 Integrated Energy Policy Report proceeding under the auspices of the Energy Commission's Integrated Energy Policy Report Committee.

The presiding member of that committee is our Chairwoman, Jackalyne Pfannenstiel. Our second member is Commissioner Geesman who has joined us for the workshop today, as well as Advisors Kevin Kennedy for Jeffrey Byron, Melissa Jones for Commissioner Geesman, and Susan Brown for Commissioner Boyd.

Today's workshop will actually cover a lot of ground related to our transportation assessment and forecast, so I will make my introductory comments rather brief. There's a few logistical items we need to cover.

Here at the Energy Commission for those who are not familiar with our site, we have restrooms just to left outside the double doors here. On the second floor under the awning is our snack shop in case you need any refreshments. In the event of an emergency, we ask that everybody please leave calmly, follow staff to the park just kittycorner from the Energy Commission here where we will convene until such time as we're allowed back into the building. We ask again that you proceed calmly and just stay alert.

For those participating by phone, we not only are featuring our Webcast in which you'll be able to see all the presentations that we're making today, but then also we have a call-in number that allows you to ask questions and to make public comment at the appropriate times. We are utilizing the number 800-857-6618. That will allow folks to work with our operators to indicate when they would like to make comments and be allowed to do so. The passcode for that is IEPR and I'm the call leader, Lorraine White.

For information related to anything about this proceeding or this particular workshop, you can find that on our Web page at www.energy.ca.gov.

We ask those who are going to be making public comments if you would please to let either myself or Jim know by filling out a blue card. These blue cards are next to the materials on the table just as you enter the building -- or enter the room. Sorry. And you can just fill them out, indicate what you'd like to comment on, and put that in the box or hand it to one of us.

As we go through the agenda today, we'll be making several staff presentations. People can ask questions after each of the presentations as appropriate, and then of course we'll reserve public comment for after the stakeholders' presentations.

We'll be doing an overview of the proposed forecast and infrastructure assessment and then get into specific forecasts that are a part of that assessment, including our fuel price forecast, our demand forecast, and our two import forecasts for both crude oil and fuels, after which we're having several individual stakeholders make presentations include David Wright with Plans All American, James Holland with Kinder Morgan, Jeremy Cuisimano from the Strategic Petroleum Reserve, U.S. Department of Energy.

We're also going to be hearing from WSPA by Gina Grey. And to the extent that I have missed anyone, please forgive me, but Jim is aware of all of the folks that will be making presentations today.

This particular forecast is part of the core requirements for the integrated energy policy report. We have already had workshops to discuss the assessments for natural gas and for our electricity forecasts. These assessments and forecasts require us to look at supply, demand, and price over time.

We rely on input from various parties, including market participants, consultations with various agencies at the federal, state, and local levels, as well as inputs from various other interested parties and stakeholders, consumer groups and the like.

From this information, we develop our assessments and forecasts, identify various issues associated with these forecasts, and from that information recommend appropriate policies to resolve these issues. The statute requires us to adopt our integrated energy policy report every two years on odd years and then to conduct an update of key topics related to these assessments on the even years as part of our update process.

The 2007 proceeding began in the summer of 2006. We issued our scoping order on August 1st. We have been conducting data collection and preliminary analysis since October. This will continue well into June. From that point, we will be developing major staff papers and providing those to the public for review.

I've featured in here on the fourth bullet our AB1007 report completion date. This is a related analysis and proceeding that will in fact be considered as part of this forecast. The completed AB1007 report is to be done by June 30th and communicated to the Legislature and Governor.

It is our alternative transportation fuels plan and the information in that plan will be considered as part of the final transportation related forecast and assessment. So the information there will be incorporated and considered.

We have been conducting workshops since the end of 2006 and they will be continuing all throughout the process as we develop our 2007 IEPR report. The committee plans to issue their draft IEPR report in late August for workshops that will be held in September. We plan to adopt our final

2007 IEPR report on October 24th in time to transmit it to the Governor and the Legislature on November 1st as statutorily required.

As I had mentioned earlier, all of the information related to this proceeding is on the Commission's Website. I've provided information here on the appropriate context for the transportation related forecast. This is also featured in the notice for today's workshop.

And then I've also indicated the contact information for Tim Olson, the project manager for the Alternative Transportation Fuel Plan required under AB1007. And of course if you need any information on any of the topics that we're covering on this IEPR, you can contact me.

Is there any questions about the day's agenda or the materials we will be covering? If not, I'd like to pass it onto Jim Page.

MR. PAGE: Thank you, Lorraine. Good, Commissioner Geesman and Advisors and good morning to our guests and staff. Today staff intend to discuss our transportation energy demand forecasts and our infrastructure assessment work -- primarily import infrastructure.

I apologize first off for the tardiness

of the report. There's no excuses. We apologize. I think the only way we can really make amends for the lateness of the report getting out is by being very thorough in our presentations and sticking around as long as it takes to answer your questions.

And as Lorraine reminded me, we have a May 18th date for written comments on the notice now, but we will accept comments for probably at least a week after that. In fact for my purposes, I would accept comments at any time, but for the purposes of the proceeding, we probably need it more timely.

I'd like to keep the meeting informal. We want -- as I say, we want to answer questions. Following the staff presentations, we have a -- some guest presenters that we're privileged to have here today. Lastly, we would invite public comments on any of these topics.

Our objective today is to cover five topics. Originally we want to talk about the overall framework and approach that we're planning on using for the transportation work and I will present that momentarily and then I will also continue with the crude oil and transportation fuel price forecast.

Malachi Weng-Gutierrez will follow me with his presentation on our proposed demand modeling methods including methods, inputs, and assumptions, and finally Gordon Schremp will discuss our crude oil import projections as well as our fuel import projections.

Our approach builds on available models -- computer models in the transportation and fossil fuels office. We'll be using updated information. As I said primary -- much of the focus will be on our import infrastructure. We're adding some new elements, including attempt to determine off-road and out-of-state demand for fuels.

We'll be adding a couple new classes of vehicles to our alternative fuel vehicle choices in the demand modeling, and we also hope to assess ethanol import infrastructure needs as well this time around.

We believe that this adaptable framework for future reports and we would like to build on this in the future.

This schematic may help illustrate what we're attempting to do and how these components all fit together. I mentioned the models. The CALCARS model is our light-duty vehicle choice and fuel use model. The heavy-duty sector is modeled with a freight model and transit model and aviation model for our jet fuel demand.

Among the updated inputs to the models include -- and fuel prices starting from the upper left and working around. I'll be discussing the fuel prices. Malachi will be talking to the economic, demographic, and other data. The vehicle attributes projections are obtained by contractor. They're essentially the offerings of the vehicle manufacturers given a certain set of conditions.

The DMV database has been updated to 2005 and provides vehicle counts for the freight and CALCARS model. The household and fleet survey is the means by which we obtain coefficients that -- for the modeling of consumer choice in the household and fleet sectors in terms of light-duty vehicles.

Other updated data will be -- the upper half of the diagram will largely be discussed by Malachi later. The lower half of this diagram will primarily be discussed by Gordon and will include updated assessments of refinery capacity for both processed capacity and distillation capacity as well as an update of our expectations about crude oil production in the state.

And before I continue with the fuel price forecast, I guess I should stop and ask for questions at this point, if we have any. And I'll continue with the price forecast.

The challenges and conditions that we're -- we face in developing this forecast are shown on this slide and really not much different than a couple years ago. We're obviously facing -- and you all well know -- continuing uncertainty in oils and fuels markets.

We also have a requirement -- ongoing requirement to be consistent with natural gas price forecasting and other units of the IEPR modeling. This has required -- well, I get into what that requires, but we need relatively detailed documentation of assumptions for this -- for that purpose.

We lack, however, an in-house world energy model. We're not able to forecast world oil prices from a model. And finally these analyses will require annual average forecasts, so called point forecasts.

Our approach is to use the EIA oil price forecasts, the high reference and low price forecasts. Our reasons for doing this are that this -- as I mentioned for the purposes of natural gas price forecasting, this is a well-documented, well-understood, well-worked, and well-reviewed modeling system that the oil price forecast is an input to.

It is publicly available unlike many oil price forecasts -- the documentation is, and it has a -- as I said, a high reference and low price forecast which we need for elements of our import requirements assessments.

We will secondly use historical data on the relationship between world oil prices and state fuel prices, specifically we call it spreads or margins between those prices. We have consulted and are continuing to consult with other offices on the E85 prices and electric rates for plug-in hybrids which are the two new technologies that we're including in the CALCARS models this cycle.

And the forecast horizon is the 2030 is the EIA's forecast horizon and corresponds with

AB1007. It's convenient for their purposes.

This slide shows -- this graph shows the track of the U.S. Refiner Acquisition Costs of Imported Crude from '68 to 2007, obviously a wide variation. This is -- this index is a convenient one for our purposes. It's forecasted by the EIA, so the historical record and the forecast record are in similar indexes.

I've added the world oil -- average annual world oil demand growth rates in the brackets at the bottom and it's the high growth rates in early years, slowing down in the '70s and '80s when the prices spiked, averaging about 1.6 percent for quite a while: 17 years through the late '80s and '90s.

And then the more recent period where demand has picked up considerably, at least through 2005. It appears to have dropped off a little in '05 to '06.

MR. GEESMAN: Jim, what's your last value?

MR. PAGE: For '05-'06? 1.2 percent.

MR. GEESMAN: And I'm looking at your graph --

MR. PAGE: Oh, I'm sorry.

MR. GEESMAN: -- which appears to be trying to estimate acquisition cost of crude oil. And you said that EIA uses an annual average.

MR. PAGE: Right.

MR. GEESMAN: So that last one is --

MR. PAGE: 2007 was estimated through April.

MR. GEESMAN: So that --

MR. PAGE: Oh, the number?

MR. GEESMAN: Well, I don't care about the number. I'm just trying to -- I think I'm looking at a plot of dots that each represent an annual average --

MR. PAGE: Correct.

MR. GEESMAN: -- except for the last one which --

MR. PAGE: Correct.

MR. GEESMAN: -- is some hybrid three- or four-month average.

MR. PAGE: Exactly. Yes.

MR. GEESMAN: And there's some value in putting that three- or four-month average on the tail end of the graph?

MR. PAGE: Only that I probably would have been asked if it hadn't been there.

And just to get a sense of the variety of oil prices that one confronts in the industry. Obviously the U.S. average price of oil is going to combine many of these indexes.

And I just wanted to sort of demonstrate -- most of you know this -- that the different quality crudes have different prices. So the numbers we read in the paper tend to be for light sweet oils typically WTI, West Texas intermediate.

And interestingly, the West Texas intermediate number is unusually low on this index at this date. This is just a point in time here because the McKee Refinery in Texas being out reduced the demand for the oil that's stored at Cushing so that depressed the WTI price. It's usually much -- at least as high as the brand price.

And you can see on the West Coast the types of oils we get tend to be a lower quality, many heavy oils, and this is kind of one of our premium oils actually and it's -- and we import a variety of crude oils from the Middle East, Latin America, and so forth.

And this slide is also very similar to

the slide I had two years ago. The factors causing our current relatively seemingly pretty high prices for oil and fuel are primarily driven a lot by high petroleum demand worldwide.

Geopolitics, we all read the paper. Problems with Iran and its nuclear program. We have Iraq and the war, Russia. But I think one of the prevailing themes that's been prominent this last few years is what I call resource nationalism and it presents itself in a variety of ways. Difficulties for the national oil companies of many OPEC nations are very strong and they're resisting and the countries have been resisting and thus poor investment in their countries.

Similarly Russia has muscled out a lot of the private companies in favor of national companies. Same thing in much of Latin America, Venezuela, Ecuador, Bolivia, Peru, and so forth. So these are all reducing access for foreign investment -- international oil companies in their resource areas.

MS. BROWN: Jim, I had a question.

MR. PAGE: Sure.

MS. BROWN: Is that primarily with the OPEC countries that you're seeing this trend toward nationalism and away from private sector investment?

MR. PAGE: Not necessarily. A lot of it but no, not necessarily. Russia, for instance, is not an OPEC country. Ecuador -- well, is talking about becoming an OPEC country. They've recently taken over -- the state has taken over many oil fields there.

MS. BROWN: And on the high world oil demand, is that a general trend or is it concentrated in areas like China where they have astronomical growth?

MR. PAGE: China is obviously a very important driver in that and India as well and -- another -- go ahead.

MS. BROWN: And -- I'm sorry. And then dollar devaluation is in effect driving up the acquisition price for U.S. refiners.

MR. PAGE: Yeah. I'll get to that as I get to the bottom of the list. It's -- rising project cost is another factor that's been coming up a lot from upstream to the downstream. It seems like cost overruns are becoming very common in major projects.

Between the resource nationalism as I've called it and these rising project costs, we're getting what I believe is kind of a constrained investment in production, again upstream to the downstream. I think there's a sense of uncertain about where to invest and what to invest in.

Another obviously very important factor recently has been refinery outages. I can't recall when I've seen so many refineries go out in such a short period of time. And this has led to low inventory, especially for gasoline.

And other factors, weather, obviously you've got a cold winter and -- driving up heating oil prices and then that drives the whole complex of prices up. We're also dealing with a renewed -- a preoccupation almost with the hurricane season even before it gets here and the anticipation of that and anticipation of landfall of hurricanes has made everybody very sensitive. Prices have almost reacted to that before it happens.

And lastly dollar devaluation. This has not been so major recently as it was two years ago, but the dollar has not gotten any stronger. If anything, it's a little weaker and that tends to drive up prices that are set in dollars compared to other currencies.

This graph compares the Energy Information Administration annual energy outlook 2007 with the outlook for 2005 oil price forecasts. The 2005 prices were what we used in the last IEPR. They are the lowest three here on the left and we've -- there were originally four. We've excluded the lowest of the four because we never really even used that one the last time.

But obviously the events of the last two years -- last several years, annual -- the EI has raised their oil price forecast and expectations considerably.

The highest oil price forecast that we have this time around is 30 to $40 higher than the highest for two years ago. The reference case is about 30 -- declining to $20 higher than last time around.

MR. GEESMAN: Jim --

MR. PAGE: Yes.

MR. GEESMAN: -- can I ask you to go back to that --

MR. PAGE: Sure.

MR. GEESMAN: -- graph. What are the left-hand dots based on? I mean you start everything in it looks to me '04, yet you're describing an '05 and '07 forecast.

MR. PAGE: I think I should have excluded all of that. I'm sorry.

MR. GEESMAN: And if I --

MR. PAGE: It should be lopped off at 2007.

MR. GEESMAN: If I look back -- and I think this is the fifth one of these that I've sent through, wouldn't I see a pattern in the EIA reference cases where we've consistently assumed declining real prices because we just can't believe that we're at such high levels today?

MR. PAGE: That is apparently what they expect -- by this graph.

MR. GEESMAN: I wonder if you'd prepare for the committee then a graph that goes back over the last five EIA forecasts so that we could graphically see that as we prepare our report because I do think that there's at least in hindsight a bit of a consistently flawed perspective that's characterized the forecasts over the last five years and I think unavoidably influenced the approach that policymakers take to the subject matter.

MR. PAGE: We can certainly prepare that. I would -- I guess I've been at this long enough that I would even take a longer view. If you go back to the '80s -- late '80s, you can find price forecasts to a hundred dollars in the dollars of that day which is greatly more than a hundred dollars in today's dollars. For most of the '90s, the forecasts were high, higher than at least prices continued through the '90s and into our current year, if you will.

And as prices started to ascend up in this last four- or five-year period, the EIA like I would say almost everyone else has been slow to kind of catch up to that and ultimately we don't know if this is an ascension, if you will, that will continue or if in fact it's -- we're trying to find a peak or some -- maybe not even a peak, but someplace where prices can find a settling point.

It's not known to me of course what that will be or how high that will get or what we can expect, but I think people are sort of searching for that sweet spot.

MR. GEESMAN: Yeah. I'm less interested in what the right forecast is than trying to understand what the parameters of the forecast being wrong are and I look back over the course of the last five or six years of consistently projecting declining real prices and I think I've got an explanation for why we've been anesthetized in terms of our infrastructure requirements or fuel switching priorities because if you do look out and see a declining price environment, it changes your perspective from what might be in the cast if you saw either constant real prices or more increasing real prices.

And I think the challenge for government, both at the state level and the federal level, is to try and bound that uncertainty with policies that hopefully are robust across a range of forecasts.

MR. PAGE: I think anesthetized is a good word because I think it occurs throughout government possibly certainly, but also the industry. If people don't have those high expectations of prices, the investment pattern is not the same as if they did and then that tends to create its effect of insufficient investment.

So, you know, I don't know how that resolves ultimately, but I think it's throughout the sector.

MS. BROWN: Jim, I wanted to ask, did you examine any alternative oil price forecasts? You gave some very good reasons I think for reliance the EIA forecast, but were there other alternatives examined that might shed some light on some other ways of thinking?

MR. PAGE: Yeah. In a later slide, I'll show some of that.

And I don't want to get too bogged down in this. I just wanted to provide this sort of informationally. These are among the outputs you get for the different oil price cases from the EIA's 2007 outlook.

Now these are outputs. Oil price is an input. This is -- oil price forecasts are developed by EIA as a kind of a group process -- a group thing, as I understand it, largely trying to understand what OPEC strategizing would be, how they would manage their production to effect a certain price path over time given a certain set of resources without -- maximizing their revenues, but at the same time, not destroying their market.

So oil price and I believe GDP are in puts. The most of the rest of this is outputs and

I'm just providing this for information purposes.

And, Susan, as you asked, this graph compares -- and in their annual outlook, EIA presents -- compares their forecasts with others. These are what I would say reference cases or base cases for the variety of organizations. GII is Global Insight. EEA is Energy and Environment Analysis. DB is Deutschbank. SEER is Strategic Energy and Economic Research; EVA, Energy Ventures Analysis, I believe.

And all of these groups provide long-term forecasts comparable. Now, the difference is -- and you have to make this sort of mental adjustment. The EIA and IEA prices are for average imports. The EIA average import into the U.S.; for IEA, the average price to import into an OECD country.

The remainder are all for light sweet crudes. So the difference in the indexes alone is around 5 to $7, so you have to sort of mentally raise the blue and purple bars by that amount. And in doing that, you see fairly quickly that those two are in the long term by far the highest.

I also wanted to show on the short term, since I can't believe I'm going to get through today without some discussion of current prices, the -- I wanted to compare the short and long-term EIA forecasts and then throw in the NYMEX futures and I have a few other figures I'd like to toss out.

The yellow and the purple lines that move roughly in parallel here are the EIA's long-term prices. The lower one is their refiner acquisition costs. The higher is the light sweet price track and that's from the forecast I'm proposing using.

The EI also puts out short-term price forecasts. This is the most recent one I had when -- as of last week. And here the red is the short-term outlook for 2007 and 2008 for WTI and the green is the short-term refiner acquisition cost.

So they're substantially -- or significantly lower, $5, than the long-term price forecast. I also included the NYMEX, the blue. Now, this first number is kind of a mongrel number. I took the first four months of the year, average price for WTI, which is what NYMEX is indexed in, a light sweet crude, and weighted that first four months of actuals with eight months of futures and you get a price fairly close to these others for the short-term EIA.

And the longer term, the NYMEX follows a track slightly higher than the EIA long term for a light sweet crude. Of course as you go further out on a NYMEX projection, you're getting thinner and thinner activity, but I just wanted those for comparable purposes.

I also have information -- petroleum intelligence weekly survey for several consultants, gave a range of about $54 to about $66 for the 2007 price and an average -- which averaged about $62. So again in the ballpark of the EIA short term.

So I guess the conclusion is that the long-term price we're proposing using for our forecasts is actually higher than most short-term expectations except with the spare exception of the NYMEX.

And since I'm sort of coming to the end of the crude oil part of this forecast, I believe I should stop for questions, if anyone has any.

MS. BROWN: I guess I had one more, Jim. When you compared the various oil price forecasts, you said that was the base case comparisons;

right --

MR. PAGE: Correct.

MS. BROWN: -- on your prior slide?

MR. PAGE: Right.

MS. BROWN: Did you do a similar exercise for the high price cases and if so, what was -- would be divergence?

MR. PAGE: I'm not even aware of other high price forecasts. I know IEA does not do one and I haven't seen these other sources directly, so I don't know that they're -- how high they would be if in fact they even exist.

MS. BROWN: So no one wants to stick their necks out.

MR. PAGE: Yeah. It's -- used to be you could get people to stick their neck out in oil price forecasting fairly easily, but those days are long gone.

MR. KENNEDY: Jim, one other question about the high price forecast from EIA. I don't know if this is explicit in any of their discussions of it or if there is any fair way to characterize it, but is that high price forecast intended as a 75 percent percentile sort of forecast or 90 percent percentile type forecast?

Do you have any sense of that or is that explicit in the way they describe the -- what they're doing?

MR. PAGE: I don't think it's based on probabilities. I have my opinions or my judgments about what those might be, but their characterization of the high and the low are as I recall a 15 percent greater or lesser ultimate resource of oil. So if you have the USGS numbers for the reference case, you just moderate them.

And interest -- I mean it was one interesting feature of this is that the -- in the high price case with assuming that 15 percent lower ultimate resource, 2007 is the peak year for oil -- for world conventional oil production. Basically it flatlines from then on according to their, you know, modeling work.

Are there any questions from the phone? Okay. With that, I'll move on to the transportation fuel price component of these projections.

To develop a fuel price forecast, we have different pieces. The first is the -- as we discussed, the forecasted oil price in cents per gallon and then second is the historical spreads or margins for fuel prices, what I'm calling, as I think it should be technically called, a crude oil to rack price margin which is sometimes called the refiner margin and the rack price to retail ex-tax price margin which is sometimes referred to as dealer margin. There are obviously several kinds of wholesale prices you could use. Rack price is not the only one, but it's the data I had.

And then finally add the state and federal excise taxes and fees and state sales tax.

MR. GEESMAN: How long a historical period do you use to determine your margins?

MR. PAGE: Four years and I'll get into that in some detail here. This graph shows the crude-to-rack price margins, the refiner side of things over time. The '97 to '02 and '03 to '06 time periods are not directly comparable because there's a slightly different index used.

I don't think it amounts to much more than a few cents, so I think -- for illustrative purposes, I think this is okay and clearly a picture of rising margins over time.

Among the variables, it's -- I've indicated pre- and post-phase 3 gasoline, but there are -- other variables that come into play have been the -- during the '97, '98, and '99 time period roughly through here, we became more dependent on imports. We actually became a net importer of finished fuels. So that tended to add to prices -- to add to margins.

And then of course in 2006, we had to deal with the ultra low sulfur diesel requirements.

This presents a more seasonal, if you will, more detailed depiction of the California gasoline and diesel margins for both the refiner side and the dealer side. One of the interesting things is how flat the dealer side has been, and these are in nominal cents per gallon. This has not been adjusted for inflation. So you have to kind of tip both lines down a little -- or a best fit line run through those would have to be tipped down a little bit to adjust for inflation.

But the story from this is how much seasonality -- how much effect you get at seasonality and volatility. If we go to the first of the year -- and go to the first of the year and again -- and then once again and of course you could add 2007 to that too, so clearly -- as I did this analysis, I felt it was important to use whole years. That way you captured entire cycle -- annual cycle, all the different fluxes in each annual cycle.

But again -- and again it shows the increase of -- on the refiner side margins over time.

This table shows the prices as calculated for various years averaged over certain years, and it shows, for the different price cases, what years I assumed the average price would be for my forecasting.

The highest price case, I took the two highest years. The base case -- added another slightly lower price year and then in the low price case, all three years back to 2003, the post phase 3 time period.

The crude-to-rack margins for gasoline have risen slightly. They're slightly higher, almost 5 cents from the low to the high for gasoline, but the really significant change has been in diesel which is almost 15 cents. Again the rack-to retail margins tended to be flatter and interestingly are actually inverse or running in the opposite trend. They actually are slightly higher. So there seems to be some give and take between the dealer and refiner side of things, at least to some extent -- some small extent.

And these are the values that I used as the second piece of the fuel price projection, added to the oil price in cents per gallon, these are the prices for the different fuels on the crude-to-rack and rack-to-retail ex-tax margins that were added to price. And these are in 2007 cents, so they're adjusted for inflation.

And this graph shows how that plays out. The -- on the low case, RFG and diesel prices are largely superimposed, so virtually identical in other words. And the -- because the margins were kept constant in real terms, the flux, if you will, in the, say, the reference case was largely attributable to the crude oil price forecast.

Some further points, however, and these are important. The first is that the date I had and used for the margin calculation was phase 3 gasoline, 2003 to 2006. Currently -- at the time that I did this, phase 4 was kind of a -- I started this process, but phase 4 gasoline -- the possibility of a phase 4 gasoline was still a distant possibility. Not much was understood about what it would involve and it didn't seem like it would be too big a deal.

However, as time has gone by -- and maybe Gordon Schremp, who's been actively involved with ARB and the predictive model work, can address this, but it seems like it's possible there may be in the ballpark -- rough ballpark of a maybe 5 to 10 cent possible increase due to that change. Now, that's all -- I have no data and I'm just trying to put out a -- kind of a ballpark number -- the possible impact that that could have.

Partly that would be cost. Partly it would end up being the volatility that tends to accompany changes in fuel formulations.

The second assumption is that -- and this is also fairly significant -- we are assuming constant real state and federal excise taxes and fees, which means that legislators in Congress are going to have to raise gasoline and diesel excise taxes -- highway fuel taxes, whatever they're called. This has not happened in quite a while and there's obviously been a lot of reluctance to even touch this subject.

But for this forecast, we're assuming that those excise taxes remain constant in real terms, so they have to be raised in nominal terms.

And finally we don't attempt to incorporate any effects of greenhouse gas reduction regulations which could be revolutionary even, but that's not even attempted.

Just for comparison purposes, there aren't very many California specific gasoline price forecasts that I'm aware of -- long-term ones anyway. You can infer one or derive one from the EIA's forecast. They have a -- they project gasoline prices to the -- in their modeling.

These two -- this graph shows the reference case or base case for the CEC, the one I'm proposing, and the EIA, if you assume that their gasoline price projection for the United States is lowered by the amount that historically it has differed from California, which is about 25 cents -- so if I add -- rather add it.

If I took the U.S. -- the EIA's U.S. gasoline price forecast and added 25 cents to that, you get the blue line. And that's obviously substantially lower than the estimates I'm proposing today.

Part of that is from -- a small part is from their assumption that federal excise taxes do not grow at the rate of inflation, that they're kept constant in nominal terms -- or yeah. Yeah. So by the end of the forecast, you could -- if you -- if they assume the same thing I assume, you could add maybe 7 cents by 2030 to their -- the blue line, and that would gradually be phased in from zero at the beginning to 7 cents at the end.

But otherwise, the remainder of the difference since we're using the same oil price forecast is refiner margins probably -- most of it.

Now, I'd like to switch gears slightly to -- since I -- as I mentioned, we're going to be trying to model E85 in flex -- use in flex fuel vehicles and electricity rate -- electricity use and demand in plug-in hybrids. We need E85 price forecasts and electric rate forecasts for plug-ins.

And as I mentioned also, this work has been done in consultation with other offices at the Commission. It's to some degree more or less outside of our expertise, so we've had to go to those offices.

This case -- in the base case, we've assumed that the value of -- that the price of E85 is determined by its value in the blend market. That is, as long as ethanol can be blended into gasoline and sold at the price of gasoline that that's -- the price of gasoline on a gallon basis is what ethanol is worth. And that's in the base case.

At the other end of the spectrum, if you will, the -- what we're calling an -- what I call an aggressive alternatives case -- Malachi will be discussing this further in his presentation -- is a case where we assume more favorable conditions for ethanol pricing.

And in this case, the principle was that we base it on a gasoline-gallon equivalence. So in simplest terms, the gasoline price was divided by 1.34 and I think we -- I've discussed in the staff paper, briefly at least, and this is, as I say, after consultation with other units in our -- in the Commission.

So we have two playing fields, if you will, for the E85 prospects and two different cases for the demand forecast.

And lastly and the most -- the least developed of our projections and forecasts are for the average plug-in -- statewide average plug-in hybrid electricity rates. As I repeat -- keep repeating is they're still being developed. We're still in consultation with the electricity units and commission who work with this.

But we're, at this point, sort of seeing initial estimates at ranges of 16 to 24 cents per kilowatt hour in the base case and 7 to 12 cents per kilowatt hour in the aggressive alternatives case.

I -- Malachi has looked into this a little more than me, so if you have questions on this particular thing, I may have to defer to him, but, in any case, again I'll emphasize that this is still being worked on and in the weeks to come, we will have to come to some fairly fast conclusions about this because we have to get the modeling work going.

And since that largely concludes my presentation on prices, I open it up for questions. Yes.

MR. EAVES: I'm Mike Eaves from the California Natural Gas Vehicle Coalition. I'm wondering with the -- on the EIA -- EIA has four projections of which you've thrown out the fourth projection; is that correct?

MR. PAGE: That was from 2005. We -- 2005 was an unusual year because prices were changing so much. They actually added oil price cases --

MR. EAVES: Okay.

MR. PAGE: -- and we dropped the low price case in any case, but for 2007, there are only three, high, reference, and low, and those are the ones I'm using currently, just those three.

MR. EAVES: Yeah. I'm encouraged in looking at the EIA data and seeing that now they've got a high price forecast that goes up not down and I'm wondering though when you're talking about your modeling efforts on your last slides, you always reference the base case. Is the Energy Commission going to just focus on the base case or are you going to model the scenarios for that high price -- high oil price for gas.

MR. PAGE: We will be modeling -- and Malachi will discuss this -- seven cases ultimately for high base and low prices, assuming -- I call it Pavley and non-Pavley cases for short. It's AB1493 I believe rules for vehicles -- and then a seventh case which would be this aggressive alternatives case which we try to, you know, pump up the possibilities for alternative fuels, the ones that we're capable of modeling with the CALCARS model.

MR. EAVES: Okay. I appreciate that, but I think that, you know, there have been a lot of comments over the years by many folks, not just myself, that maybe that high price -- high oil price scenario is one that ought to be looked at more than the other cases. Thank you.

MR. PAGE: Uh-huh. Yes. And for our work -- I mean you're right. There is a -- sort of a pull for the base case to become the only case. We don't see it that way. We're modeling seven cases and we want to capture the range of possibilities as best we're able.

So for our work -- and in fact the high and low case are in fact essential for -- the demand outputs from those cases are important for our fuel import requirements. We need to test ranges of possibilities.

So for our work, all the cases were relevant, but I'm sympathetic. There is sort of a tendency over time for the base case to emerge as sort of the only case.

In the current circumstances with the Pavley rules still not settled, whether -- you know, whether they go into effect or not or when if they do, we kind of have two base cases. You know, so -- you know, and then this aggressive alternatives case will be -- will assume base case conditions not -- we won't be getting into high and low with that one because we have sort of run out of contractor money to do that.

But that -- so then in a sense, we'll have three base cases, three possibilities. Yes, please.

MS. TURNBULL: Hi. I'm Jane Turnbull from the League of Women Voters. I'm not sure if this is relevant or not, but the fact that E85 has a very different heat content then does gasoline or even our current fuel, are you looking at the price differences in terms of the relative heat content of these fuels?

MR. PAGE: In this graph, that's essentially what we're doing. As I say, in the blue line, the prices are equal on a gallon basis, but you're right. The next content of E85 is much lower, so it's obviously going to be at a competitive disadvantage in that case.

The red line controls out that difference. It assumes, you know, that the price of E85 is set to the equivalence of gasoline in terms of getting you down the road -- how far will it get you, what the -- it concludes the heat content of the fuel and the efficiency of the fuel as it's used by the vehicle.

MS. TURNBULL: I mean one reason I ask this is because I note a very significant difference in the mileage that I get on my Prius in the winter and in the summer and it's more than 10 percent. So I'm wondering what an E85 fuel is going to really look like.

MR. PAGE: That's an interesting question. I'm not sure I know the answer.

MS. FRY: I'm Barbara Fry with the Air Resources Board and my staff is working with the Commission on the AB1007 report and I would just echo the Commissioner's comment on the price forecast that since EIA has historically underestimated the cost of prices in the future, that you consider having a case that would have a higher projected price as well.

MR. PAGE: And as I've tried to emphasize, we take the high case seriously. It's not just, you know, another something else you do. I've also though -- have to caveat a little the EIA's historic record. As I've stated, you know, it goes way back. Their price forecasts in days of yore were very high and there's always an adjustment period, but not just by the EIA but almost anybody who forecasts prices on an ongoing basis to sort of be behind the times.

And to not know when peaks and valleys are occurring, it's sort of an institutional sluggishness if you will.

MS. FRY: You may just want to consider a case where there's a steady increase over time as a possible scenario since that has been happening historically.

MR. KENNEDY: Jim, to some degree following up on that, do you feel that the high price case that you have to the extent that the policymakers are interested in looking at essentially how the policies would -- that we consider would fair under an extreme high price that that actually captures -- the high price forecast captures an extreme high price scenario or if it's more of a moderate high price scenario?

MR. PAGE: No price forecast is going to

stay above all the possible spikes in prices that could occur. In fact you have to look at these lines as sort of central tendency around which prices fluctuate both above and below, sometimes a great deal. So, you know, I believe that the high price case is high, but it's not inconceivable either and I think it should be planned for as I also -- we forget about the low price cases. They kind of get lost in the dust these days, but you might ask yourself as a policymaker what if prices decline because they have in the past. That is not unheard of. Yes.

MR. McKEEMAN: Good morning. My name is Jay McKeeman. I'm with the California Independent Oil Marketers Association and I'm really not sure where this comment fits in in the dialogue today, but I figure now is as good a time as any mostly because it deals with something that I'm not seeing in the materials today.

Can we flip back to the California gasoline and diesel margins slide?

MR. PAGE: This one or that one?

MR. McKEEMAN: That one. Thank you. It's kind of hard to see, but the -- what I'm focusing on is the so-called dealer margin, the lines at the bottom, and if you take a look at the end of the chart there, you see a fairly significant decline in what's called the dealer margin and that's certainly something that our members have been experiencing is a rather steady decline in the wholesale margin or the rack-to-retail margin.

MR. GEESMAN: That'd be worse if you put it in real dollars. These are nominal dollars.

MR. McKEEMAN: That's true.

MR. GEESMAN: That'd be a downward sloping line if you put it in real dollars.

MR. McKEEMAN: That's right. That's just something that I'm suggesting that needs some focus and particularly as it relates to alternative fuels and that gets me to the point of the omission that I've seen and maybe it's just not been developed yet or it's in the process of being developed.

But one of the key issues that our members are encountering is the ability to put in alternative fuels infrastructure and that include bulk tanks, blending components, E85 pumps and tanks, that type of infrastructure and that's something that I haven't seen in the materials that have been handed out today is a focus on that infrastructure issue and this is really downstream from the rack.

And there is -- but if you want to accomplish effective and quick implementation of alternative fuels distribution, you have to look at that component. And when you compare it to the margin -- the declining margins that are available for capitalization of those types of improvements, you got a pinch point. And it's just something that I would like to see the Energy Commission focus on going forward and it's certainly something that our members are focused on. They're trying to -- scratch their heads and figure out in a declining margin era how do you capitalize fairly expensive improvements to make fairly big changes in the distribution system.

MR. GEESMAN: What proportion of the retail market do your members represent?

MR. McKEEMAN: A fairly small portion of the actual service station component in the state, maybe 20 to 25 percent, although those numbers are changing because there's a fairly large distribution of retail stations -- or distribution -- sell off of retail stations by the major oil companies to chain operators and we're trying to get those people involved in our association more and more.

But beyond that, there is the commercial distribution which is to agriculture, industry, a variety of commercial interest. So we represent probably 95 percent of that distribution chain. All right. Thank you.

MS. BROWN: I'd just like to respond that we're well aware of the issue regarding alternative fuel infrastructure and that's going to be a major theme in the report that we're working on the alternative fuels plan, Jay, so you should track that proceeding as well.

MR. McKEEMAN: Right. Well, I'm just starting to pick up on stuff, so thank you.

MR. PAGE: Any more questions? Okay. I will -- with that, I'll close and introduce Malachi Weng-Gutierrez to discuss the demand model.

MR. WENG-GUTIERREZ: Good morning, Commissioner, Advisors. My name is Malachi Weng-Gutierrez, and I'm going to briefly discuss the methodologies and inputs into the transportation energy demand forecast.

There are a couple reasons why we perform demand forecasts. Probably the most basic is to get an understanding of the trends and items in the market that affect transportation energy demand. This allow us to look at how policies and measures might impact that demand and allow us to present recommendations and to evaluate difference scenarios in that evaluation.

Earlier this morning, Jim showed you a flow diagram of how the models interact with our overall evaluation and one of the key outputs from our overall demand evaluation is the evaluation of the infrastructure adequacy and potential needs for infrastructure given our growth and demand.

The forecast itself is actually a combination of four different models. The CALCARS model is our light-duty model -- the transit model, freight model, and the aviation models.

We are currently actually in the process of updating most of these models. In the case of the transit, we're looking at expanding the number of transit agencies that are actually being evaluated from 16 to 45, hoping to get a better representation of how transit is growing in the state and how it's being used.

Again here is that flow diagram that Jim had brought up earlier this morning. It shows the four models that are used in developing the in-state fuel demand and some of the inputs into those models. As you can tell, the DMV database and fuel prices, economic, demographic, and other data are important in multiple models.

In general, the methodologies that we use are primarily mathematical based. We use two primary types of mathematical models to develop our demand forecasts. The first is a discrete choice method. Specifically for our model -- for the CALCARS model, we're using a multinomial logit equation that basically calculates utility of making certain vehicle choices. Households are making those choices under certain conditions.

The multi-variable regression type of model is used and represents what is used in the transit, freight, and aviation models to estimate transportation energy demand growth. That is specifically done by taking historic data and input data from different sources and creating basic multi-variable regressions that represent future demand and potentially other outputs such as VMT.

Again I think what I want to emphasize or focus on are a few -- primarily the CALCARS model, but there are inputs that are shared between the models and I'm going to go ahead and briefly go over those as well. And I'm going backwards in my slides, so I will go forward in my slides.

It is our intention for the IEPR forecast to evaluate these five fuels. They have been evaluated in the past, and the only one that actually we're increasing -- we're going to evaluate that's new to this IEPR will be electricity and that will be by including plug-in hybrid electrics in our light-duty vehicle sectors evaluation.

So again gasoline and diesel are two important and primary transportation energies that we've evaluated consistently through our IEPRs. The natural gas component again will be focused on the transit use of natural gas. We are not going to include it in our light-duty model primarily because the number of makes and models available are still limited and I believe there's only one manufacturer of light-duty natural gas vehicles and that Honda Civic GX.

So we have decided not to include that in the demand forecast for light-duty vehicles, but it will be included and is a large component in the transit model.

Jet fuel obviously is commercial jet fuel and that's what we'll be evaluating the aviation model.

The sectors that will be evaluated in our models are the following four: light-duty vehicles, both private and commercial. That is being represented by the CALCARS model and that's what it models.

On the commercial end, we're looking at fleets distributed across California and their choices and how they're going to grow, and on the private side, we look specifically at households and how they make their decisions about vehicle choices.

For public, we'll be looking at also public transportation, freight movement, and commercial aviation. And as I mentioned, the public transportation sector, we are looking in the transit model to expand the number of agencies that we're evaluating -- we're including the development of that model.

Some of the common data that are used in the models, the first and probably the most important is the fuel price. As Jim said earlier, we use a number of different sources to arrive at our fuel prices. Gasoline and diesel are derived from EIA's crude oil prices.

The natural gas price that we'll be using comes from our Energy Commission's Natural Gas Unit. The electricity price that we'll be using is being developed by the Energy Commission's Electricity Analysis Office as well as with consultation from the demand analysis office. We're going through the process of developing those prices and would certainly be interested in getting feedback or input as to giving us maybe some additional research or studies that -- in the area of load profiles associated with electric vehicle charging.

Jet fuel prices, we are currently evaluating the use of state and federal forecasts in that evaluation. In the previous model, we did not include specific -- a specific fuel price -- a jet fuel price forecast in the model. But we are looking this time to potentially include a specific fuel price forecast for jet fuel in that model.

And E85 which Jim just mentioned was developed with assistance from the Emerging Fuels and Technologies Office. They have the expertise in that area and we've really looked to them to assist with developing what we both felt were representative fuel price forecasts for that fuel and it is a challenging topic and we would -- again if there's comments or suggestions, we would be happy to look at any information provided.

A couple of other common pieces of data that are used in the models. Demographics are very important. In past IEPRs, demographics have played a role in the changing demand that we have seen as outputs, population being one of the key components. I know in the last IEPR, we had a decrease in demand from the IEPR prior to that and that was partially due to a change in our population forecast that we used as an input. So population is an important input to all of the models.

Personal income is important as well and industrial sector activity is used in multiple models as well to reflect how their -- what growth patterns are being seen in different industries and how that's going to affect overall demand.

Most if not all of the information provided -- that are used as inputs in the demographics come from the Energy Commission's Demand Analysis Office.

The last input that is used in multiple models are vehicle counts and these are actually on-road registered vehicle counts from our DMV registration database that we have here internally and Jim again mentioned this earlier this morning that the most recent set of updated data is for 2005 and that's what we're using the upcoming demand forecast.

Again Jim mentioned this earlier. We're looking at developing seven specific cases that we'll be evaluating for demand. This is very similar to what we did the last IEPR. We are throwing in a seventh case which is a little bit more aggressive and we're looking at -- hoping to look at different types of alternative fuel penetrations and different scenarios.

The three -- or the six cases that we generally -- that we have done in the past are basically the low, reference, and high fuel price scenarios with and without greenhouse gas regulations. In the instance of the cases with the greenhouse gas regulation, we are also including the ZEV program influences to overall fleet efficiency. So we're taking that into consideration in how the fleet will develop over time and how that will impact overall fuel efficiency for the fleet in California.

So now I'd like to actually look directly at the CALCARS model and some of the inputs that are being used in that model and discuss briefly what they reflect.

Vehicle attributes play a key role in the CALCARS model. They basically represent what the fleet will look like in the future and what the characteristics are of those future vehicles are important to how a household or -- a specific household in California, what choice they will make in either replacing or obtaining a new vehicle in the future. So characterizing those attributes or the characteristics of those vehicles is important and we have a consultant that does that and these are just a handful of the characteristics that we look at for the different types of vehicles.

Acceleration is very important.

Purchase price is important. Fuel efficiency and fuel price, gradability which is basically defined as the maximum speed at which a vehicle can travel while fully loaded at a certain incline or grade.

Annual maintenance costs are important and we look at a variety of different vehicle classes. We will continue to look at the 15 different vehicle class types ranging from subcompact cars to heavy trucks. There's basically 15 classes that we look at and those will continue to be looked at. We'll be looking at additional fuel types, the ones mentioned plug-in hybrid electrics and the flex fuel markets this time around. So we will have more than just the previously 45 different types of vehicles that we looked at in the IEPR in 2005.

For the choices of vehicles, these are the variables that we look at that are important for each of the households. We look at household income, household size, the number employed in the household, transit availability, and basically what that allows us to do is create an average utility of the vehicle choices available.

The transit availability comes from the transit model -- as part of the work with the transit model. We get that availability from there and so there's an interaction between those two models that is important to note. Just that if we are consistent between those two models.

The calculation for VMT, one of the outputs of CALCARS is VMT. It does an estimate of VMT and it's based on these variables. Again household income and size are important. The number of employed in the household are important. Vehicle age comes in in this calculation, vehicle fuel price -- or fuel cost per mile is a factor and then also transit availability.

So you would imagine if fuel prices increased, the cost per mile would increase, and potentially people would choose to use transit more or replace their vehicles or react in certain ways.

The work that we're doing for the transportation energy demand forecast is supposed by two contract services. The first is the one which I mentioned defines our vehicle attributes. We're using Energy Environmental Analysis to provide us with those vehicle attributes and they are looking at those attributes taking into consideration our specific cases or price cases --

fuel price cases.

So we provide them with all our fuel prices. We provide them with current vehicle counts from California, and they then provide us with the vehicle attributes that are associated with those fuel prices. So in the case of a high fuel price, we will get vehicle attributes that will correspond to that and that will allow us in the model to look at how consumers will make choices based on those developed vehicle attributes.

The California Vehicle Survey is another one of the contract services that we have supporting our activities. It basically is looking at collecting stated preference choices from 2000 residential households and a thousand commercial fleets.

We're looking at having those 2,000 residential and a thousand commercial fleets be representative of California and so we're looking at specific regions in California. A number of our models are set up to look at specific regions such as San Francisco, Sacramento, LA, San Diego, and to how responses might be different in those different regions.

And so it's very important in the survey to make sure that we have an adequate distribution and we're properly -- we're adequately representing the distribution of residences, consumers, and commercial fleets in California. So that's an important part of that survey activity.

Some of the additional models and inputs that we have to the models are --

MR. GEESMAN: Malachi --

MR. WENG-GUTIERREZ: Yes.

MR. GEESMAN: -- if I can you a couple of questions --

MR. WENG-GUTIERREZ: Sure.

MR. GEESMAN: -- on the CALCARS element. How well historically has CALCARS predicted vehicle choice?

MR. WENG-GUTIERREZ: I know that staff has done evaluations of how accurate it has been. I believe in 2004 there was an evaluation of how close we were in hitting the hybrid numbers and we were within 500 vehicles of the actual reported registered vehicles. So that's pretty close.

I think we could certainly do some additional evaluations to determine, you know, how close we are under different conditions and I think that again the inputs that you're putting into the models may not be exactly -- may not exactly reflect what's occurring the marketplace, and so it might take running a special case to look at how the outputs relate to historic data.

But we certainly calibrate the model to historic data, so -- you know, so I think that it's in what we've looked at already, we're really comfortable with it and we've gotten some pretty good numbers.

MR. GEESMAN: And how accurate historically has the VMT estimate been?

MR. WENG-GUTIERREZ: The VMT number, I haven't looked at specifically. I think we are intending to do some evaluations and comparisons between different models that are developed in California. I know that we have looked at overall demand and done some comparisons between models to see how accurate we are and actual numbers for demand. And we're pretty close on actual demand.

The VMT I would have to take a look at.

MR. GEESMAN: I'd like to see a comparison of our VMT with that used elsewhere. Where do your demand elasticity assumptions come from?

MR. WENG-GUTIERREZ: Well, the demand elasticity -- the fuel price elasticity of demand is not a specific input to any of the models. It can be calculated from the outputs of the models to provide an estimate of what that elasticity is.

In the 2005 IEPR, I believe the elasticity was estimated at .16 and that was what was used in the futures model and some of the other models that were used in the emerging fields and technologies analyses.

This time around, that was using -- or it was based upon 2002 survey results under certain market conditions in 2005. So with this current evaluation we're performing, we are performing a survey in 2007 with 2007 market conditions And so the out -- the elasticity that we see from that survey and from the models may be substantially different since we have been seeing, you know, radical changes in fuel prices and condition as a whole has changed a bit.

So we're hoping that the survey results will give us a better characterization of elasticity.

MR. GEESMAN: And you'll have those in

time to do this modeling work?

MR. WENG-GUTIERREZ: We're hoping to have them in time for the IEPR, yes.

MR. GEESMAN: Thank you.

MR. WENG-GUTIERREZ: So again a few of the other inputs to the other models, the freight model again looks at freight -- basic truck and rail activities. It's looking at economic growth based on the volume of truck and rail activity in certain industrial sectors.

It also looks at what changes can occur, how basically can you divert traffic from one mode to another, and how has that been changing over time and how does that affect overall demand in the freight sector, field costs and exogenous trends impact and relate to the fuel economy or fuel efficiency of trucks and rail as a whole, so those are taken into consideration as well.

Fuel costs and other factors are looked at for both gasoline and diesel trucks and those are all kind of important components of the freight model.

Transit model, one of the important pieces of information we use is the reported growth of transit use. This is derived from actual data that we get from specific transit agencies, and again as I mentioned, we are trying to capture a larger number of transit agencies in California than was previously evaluated. So we're looking at expanding the number of transit agencies I believe to 60 or so in California. We hope that that represents the transit sector adequately for our evaluation.

The aviation model uses a number of different FAA forecast data as input as well as in the past versions of the aviation model, we have used revenue passenger miles to provide an idea about what aviation fuel demand is going to be in the future, and I believe we're again looking at updating that model and we may be adding some other inputs and looking at how other inputs are influencing that model and the demand in that sector as well.

That was the majority of what I've put together. I had a couple of items and a few other slides that I wanted to go through that basically look at vehicle ownership trends in California. I thought they were interesting and I just wanted to present them.

The -- this is basically outputs from

our -- the DMV registration database. So these are on-road registered vehicles and they're broken out by fuel type here. And you can see a growing trend in all areas.

This is just the actual count and what I wanted to take a look at was the actual growth rates in each of these different sectors. So the next slide I have puts the actual growth rates for each of these fuel types adjacent to the actual counts.

So it's interesting to note that although the population of hybrids is low, they are certainly expanding. Their market share is expanding and the growth rate is fairly high, one of the highest.

The second is flex fuel vehicles and it looks as though they've been consistently around 30 percent growth other than the 2004 number which I think -- I'm not sure why that's so low in that year, but definitely on average, they've been growing at about 30 percent per year.

Diesel vehicles again also are continuing to grow and it's interesting to note again all three of these other types of fuels are growing at a faster pace than gasoline vehicles.

So I think there's an expanding use of those other technologies whereas the fraction of the gasoline -- vehicles that are fueled by gasoline are not growing at the same rate as the others.

So what I wanted then to look at is what is the fraction of -- on a year-to-year basis, what is the composition of the new vehicles coming into the market. Are the majority of them gasoline? How is it changing over time.

And this is what this graph shows is again the majority of the vehicles on the road are gasoline and that's reflected in the blue, but if you look back and look at -- or do a comparison between 2002 and the 2004-2005 time frame, you see that gasoline as a fraction of the new vehicles on road has decreased from 90 percent to approximately 80 percent.

So that in 2004 and 2005, 20 percent of the vehicles coming onto the road are actually flex fuel, hybrid, or diesel. I believe flex fuels comprise 9.2 percent of the new vehicles and hybrids were 5.7 percent.

This is a look at the same data or actually this is the total data for all counts, but done on a class basis. So we have again 15 different types -- vehicle classes that we evaluate in our demand forecast. I've categorized them or -- into these five classes on the right: pickup trucks, vans, SUVs, cross utility vehicles, and cars.

And if you look at the growth pattern over the years or the composition of the overall vehicle ownership, cars has -- they have been increasing but not at a very large rate. The bold numbers between the two columns, the 2003-2004, are the average growth rates or the average growth rates in each of those categories.

And I think in previous IEPRs and people often look at the distribution of vehicle classes and say that SUVs are decreasing in market share. It looks as though from our registration data that they're still increasing at a reasonable rate, 5.6 percent, 5.7 percent there, and really what seems to be declining are the number of vans that are being purchased.

And again I think we're just looking at five years here, but it is interesting to see that the number -- or the increase is not -- the number of vehicles associated with SUVs are not necessarily declining in the same way that some people have proposed.

It may be that people purchasing vans are choosing then to purchase crossover vehicles as opposed to purchasing mini vans. So that was something interesting.

I guess you could look from 2004 -- 2003, 2004, 2005, and if you look at SUVs, there is a decline, but again on average over the last five years, there has been a fairly large growth in that sector.

And I believe that is my last slide, so if anyone has any questions, I'd be happy to answer them.

MS. BROWN: I had one question. When do you expect demand forecast results to be available?

MR. WENG-GUTIERREZ: We will have a -- we're looking -- we're getting information from our survey shortly and we're going to be integrating that in the CALCARS model and we have already run a couple of the other models and gotten some demand numbers. We have to evaluate those.

We're looking certainly in having them probably in the next month or two.

MS. BROWN: So is it premature to have you comment on the percentage in field demand growth?

MR. WENG-GUTIERREZ: Yes.

MR. HACKETT: Good morning. I'm Dave Hackett with Stillwater Associates. Two questions. One on your earlier slide when you talk about diesel, these are light-duty diesel vehicles as opposed to truck?

MR. WENG-GUTIERREZ: Those are actually including trucks. So the growth that we seeing are basically trucks --

MR. HACKETT: Okay.

MR. WENG-GUTIERREZ: -- light-duty -- the population of light-duty has been declining over the past few years.

MR. HACKETT: Okay. And then the second question is how are you guys going to forecast ethanol and biodiesel prices? Have you thought about that yet? You've got gasoline and jet fuel and diesel in there, but for the alternative fuels, have you thought about how you're going to do that?

MR. WENG-GUTIERREZ: We are not going to look at those as a specific case unless they are incorporated into that seventh case which could potentially look at that. I don't know what fuel prices we'll be using in that alternative fuel case. That's probably -- we'll look to the work with AB1007 and low carbon fuel standard work and see if there's some evaluations that might help us get an idea about what would be appropriate to use in that case, but.....

MR. HACKETT: Yeah. I think relative to ethanol, certainly 6 percent in the gasoline mix now and potentially 10 percent later on that that's one you want to think through.

MR. WENG-GUTIERREZ: Sure. Absolutely.

MS. GREY: Good morning. Gina Grey with WSPA. I had a question on your household and fleet survey. I think in the document that was produced for our review, you mentioned that consumers were not asked as to whether or not they would consider purchasing a diesel vehicle; is that correct?

MR. WENG-GUTIERREZ: No. They are actually asked if they would purchase --

MS. GREY: Oh, they were. Okay. I thought it mentioned in there where -- I guess -- and I don't know if this is really a question or a comment, but the survey was I gather 3,000 people in total and there's something on the order of about 40 million vehicles in the state and I don't know what that equates to in terms of vehicle ownership, but in terms of where the state is currently and I think the question was asked earlier about whether or not the state has been historically projecting a correct sort of mix. That may not go to the future in the sense that it appears the state's sort of on the verge of entering into a wholesale shift potentially.

And I guess there's a sense of nervousness as to whether or not these projections are being adequately treated, if we're looking at 3,000 survey responses in a several million sort of pool. And I know surveys can be very costly, et cetera, but a little curious as to how that survey gets then input to CALCARS.

So how does it influence?

MR. WENG-GUTIERREZ: Sure. The survey itself -- we arrived at the number of 3,000 -- 2,000 residences and 1,000 commercial by statistically evaluating whether or not it would be significant at those levels and those are our target goals. We may actually have a higher number of results from the survey.

They get -- the results from the survey go to one of the subcontractors. They actually develop coefficients which are then plugged into the CALCARS model. The coefficients represent the fraction of the utility associated with that specific vehicle type for that demographic.

So it's a correlation between demographic information, say a household of 100,000 annual income with three kinds, two employed. The coefficient would relate specifically to that demographic information and show the distribution of utility for different vehicles that they have been presented with.

So in the survey, they'll be asked which vehicle would you choose and they have a specific demographic associated with the respondent and then that's correlated with that coefficient. So it's the coefficients themselves that go into the model. Not necessarily the volume of responses, but how the choices are being --

MS. GREY: Okay. And I guess just a follow-up comment then. Seeing as I suspect a lot of the public don't even realize what a lot of these future possibilities might and what they are and I think the state had indicated at one point that one of their central roles is going to be to educate the public on what FFEs are, et cetera, it might be handy in this whole assessment if there's some sense given as to sort of how reliable would those survey responses be, et cetera, just so it gives a sense to people as to, you know, how comfortable do you feel with where you've ended up on this.

MR. WENG-GUTIERREZ: Sure. And I think that's one of the assumptions that I mentioned -- or that's in the write-up that talks about we are assuming that the responses provided in the survey in this year represent -- or adequately characterize people's responses in the forecast period so that given an individual's understanding of flex fuel vehicles and -- or hybrids -- plug-in hybrids actually, that was one of the challenges is --

MS. GREY: Right.

MR. WENG-GUTIERREZ: -- what is a future plug-in hybrid going to look like and how do we -- how can a consumer adequately -- you know, make a choice based on that. So in the survey itself, they are presented with information, background material, and the characteristics that they are comparing are such that it does represent that vehicle in a simplistic way.

I think we can -- we have done in the past evaluations to determine whether or not the stated preferences of the survey reflect actual ownership and that has been -- has shown to be fairly close. We've looked at what people say they're going to buy and then relate that to actually what they own and it seems to be pretty close.

Again in the instance of future technologies, it's difficult to --

MS. GREY: Right.

MR. WENG-GUTIERREZ: -- it's difficult to characterize them in a certain way, but that's definitely something we've taken into consider in the survey.

MS. GREY: It may be just helpful if you include some statements that talk about that forward looking, very difficult to --

MR. WENG-GUTIERREZ: Sure.

MS. GREY: Okay. Thank you.

MR. WENG-GUTIERREZ: Of course. Thank you.

MR. EAVES: Mike Eaves with the California Natural Gas Vehicle Coalition. You indicated in your slide that natural gas was going to be evaluated under the transit model. I would encourage you to also put natural gas in the freight model.

If you look what's happening in goods movement and port activities, natural gas is going to be a key player in that and probably should be evaluated in that market segment and not transit.

Also in evaluation of alternative fuels, I know that you're going to do the low base and high case forecasts for the other -- for gasoline with and without the greenhouse gas legislation. I'm just wondering how valuable the low price forecast is going to be in any of those projections and if the focus shouldn't be on the base case, the high case, and maybe an intermediate case between those two.

Also I'm wondering on your slide on vehicle attributes in the CALCARS model, do you think that the CALCARS model is really reflecting the current trends in shift from larger vehicles to smaller vehicles? Your data goes to 2005, but the U.S. automotive market is in a tailspin for the last two years on just that issue and I would hope that the CALCARS model looks at the 2006-2007 realities and tries to correlate whether some of those factors are really important or not.

And I guess my last comment on the -- you had the slide on the penetration of various vehicles and you show flex fuel vehicles. I'm not sure that -- you know, it wasn't until last year that some of those manufacturers had been notified by the manufacturer that they actually do have flex fuel vehicles. So if you take a look at the flex fuel vehicles and add those to gasoline vehicles, I think you still see a growth in that market.

And certainly people that have hybrids, certainly the people have diesels know what they have, but I don't believe the people with flex fuel vehicles know necessarily what they have and certainly they don't use the fuel that way.

MR. WENG-GUTIERREZ: Absolutely. Yes. And I broke out flex fuel in this instance just again to get a sense of how that population of vehicles is growing, but absolutely there's -- the limited infrastructure for E85 in California is limiting the use of the E85 in most vehicles, but again there's -- that's a potential market and obviously educating the public and providing growth opportunities and distribution for alternative fuels is important and we'll be looking at that.

To the question that you had about the data that I have up to 2005 and hoping that CALCARS will incorporate the interim years, that was reflecting actually DMV registration data. So that's our historic data that we have.

The survey that we're performing obviously is in 2007 and should reflect consumers' preferences and choices in this year. So we will use the consumer information from 2007 to fill in the gap there and so the CALCARS model should reflect today's choices and preferences. Yes.

MR. LARSON: Jim Larson with PG&E's Clean Air Transportation Group. In the late '90s, we published half a dozen different electric vehicle charging pattern behavior studies that if you haven't seen or aren't considering in your analysis, I'll make available to you. Be happy to work with you to make those available.

MR. WENG-GUTIERREZ: I'd be very happy to see them.

MR. LARSON: Are you taking a look at the time of use electric vehicle tariffs that the utilities have in effect, the E9 tariff, for example, off-peak rate for electricity is between 5 and a half and 6 cents seasonally per kilowatt hour.

Without public electric vehicle charging infrastructure, clearly most people will be charging those vehicles until broader electric vehicle infrastructure's available.

In your electric vehicle population, are you looking at only on-road vehicles or -- and again clearly the electric vehicle marketplace is far larger in the off-road segment there, so --

MR. WENG-GUTIERREZ: To the second question, we are looking at only on-road vehicles.

MR. LARSON: Okay.

MR. WENG-GUTIERREZ: Our demand forecast is an on-road demand forecast, so for the off-road demand we don't necessarily take that in consideration just yet. We are looking at developing an off-road model in which case off-road applications for electric vehicles might be appropriate to include a mitigating factor to cure out demand.

So to the first question -- or the first point you made --

MR. LARSON: The charging studies -- charging studies we have available?

MR. WENG-GUTIERREZ: The first charging study, that certainly. We have looked at a couple of other studies that have been mentioned in different docketed information. I think there was one that was performed by PG&E and it showed the percentage of distribution of charging times and I think it was 88 percent off-beat.

So we certainly are taking in consideration those types of studies. The demand -- the Electricity Analysis Office has also contacted a number of utilities to get a sense from those different tariff structures and time-of-use structures, when are people charging to get that idea. And that was incorporated into the evaluation -- or the evaluation that we're currently putting together, so -- we are aware of those and we are incorporating them.

And I think the way that we -- the one -- the way that the fuel price was broken out for the electricity sector, we did look at five or six utilities that represented the largest percentage of California consumption and we looked at their specific EV tariffs and time-of-use tariffs and then weighted them accordingly.

We also incorporated the electricity consumption allotments and those sorts of things in developing those costs, but we certainly are still looking at that and trying to come up with a good representation of what -- you know, what might be a possible future fuel price for electricity or electricity price for vehicle application.

So we'd be happy to get any comments and --

MR. LARSON: Yeah. One of the modifications to the electric vehicle charging tariff we're trying -- we're making is to avoid the charging of that electric vehicle from bumping the consumer up into additional higher cost tiers and separating out a vehicle -- vehicle charging from the overall household charging in order to avoid those higher costs.

And finally, I notice you're using PHEVs specifically in calling out electric drive technologies and it appears to us that pure battery electric or electric drive vehicle technologies are emerging simultaneously with PHEVs and would recommend you consider broadening that -- get that niche to electric drive technologies if you will.

MR. WENG-GUTIERREZ: Okay. I think for this IEPR -- certainly for this IEPR, we will not be able to include the electric specific -- purely electric vehicles only because for our survey work, we haven't been asking people whether or not they would choose a pure electric vehicle.

We have, however, been looking at the plug-in hybrid electrics. So we felt that that was a good technology that was between the two. It's similar to existing technology that seems to be taking off and so plug-in hybrids seemed a logical first step. But perhaps in the future evaluations, we will include -- perhaps in future surveys, we will include the electric vehicle as a selection choice as well. Yes.

MR. STEVENSON: Dwight Stevenson, Tesoro. On slide 4, you show the fuels that you intend to include in the transportation and energy demand forecast. Are you including E85 in -- under gasoline?

MR. WENG-GUTIERREZ: That's a good

point. We are including E85 as a fuel that we are evaluating, so I -- actually that is short sighted on my part. I should have put down either ethanol or E85 as a distinct fuel here.

MR. STEVENSON: Okay. And on E85, are you going to consider the economic effect of increased ethanol demand on food production?

MR. WENG-GUTIERREZ: We may evaluate that in our write-up. The models themselves will not necessarily evaluate that specifically --

MR. STEVENSON: Okay.

MR. WENG-GUTIERREZ: -- obviously because what they're just forecasting is the transportation energy demand, but I believe that work with the -- in the (indiscernible) and Technologies Office, AB1007 work and other alternative fuel work does address that. So -- and we are working closely with that office to come up with that demand forecast.

MR. WRIGHT: Good morning. David Wright with Plains All American. Could you go back to that slide with the vehicle trends. Just one suggestion I would have is that this is the first year that the ultra-low sulfur diesels have been available generally throughout the United States and I think you're going to see a very accelerated pickup in terms of the light vehicles that will use diesel, both cars and light pickups, and I would suggest strongly that you look at the European model and see, you know, what's happened in Europe.

You know, they tend to be very efficient there because their fuels are very expensive and I think you'll see a very significant pickup in diesel vehicles. Thank you.

MR. WENG-GUTIERREZ: Thank you for that comment. These are again existing trends and they are actually showing growth in the truck area not the light-duty diesel sector. We are modeling the light-duty vehicle sector and the future vehicle characteristics are being -- the characteristics of the vehicles that are being incorporated should represent future light-duty diesel vehicles.

So that may or may not -- I would expect that the technologies currently being used in Europe would play a role in how and what the characteristics would be of our light-duty diesel vehicles we'd see in the United States as well. So -- but again light-duty diesel is not included in these numbers as a new growing market. That will be modeled in our future demand forecast.

Any other questions? So I think I will hand it back to Jim and he'll take it from there. Thank you.

MR. PAGE: Yes. The next speaker will be Gordon Schremp and he'll speak on crude oil import forecasts and I guess after that fuel import forecasts.

MR. SCHREMP: Thank you, Jim. I thought there'd be a lengthier introduction, but -- I know it's getting closer to lunchtime and you're pretty anxious and so I will -- I'll try to get us a little closer back to schedule, but depending on the number of questions, we want to make sure there's ample time for stakeholders to ask me questions and especially the Commissioners and Advisors on either of the two presentations I'm going to be going through next.

I guess I have to find the presentations to go through them next. All right. Well, by way of self-introduction, my name is Gordon Schremp. I'm the Senior Fuels Specialist on staff in the Fossil Fuels Office of the Fuels and Transportation Division. I've been working at the Energy Commission primarily in this division for about 17 years now, and so I've developed a lot of expertise over the years just by staying awake in meetings and listening.

So that's helped and done an awful lot of analysis. So today I'm talking about, as Jim mentioned, two different topics. One is crude oil import forecast of which we do have a preliminary revised one compared to the one we did back in 2005. And we'll talk about our game plan for forecasting imports of transportation fuels.

We do not have a forecast at this time, but we will be developing one in advance of the next scheduled workshop on this subject which is July 12th in Southern California and I have a slide on that as well.

So here are some of the topics I'll be covering this morning on crude oil import forecast. The basics, you know, what do we produce, what's been happening both domestically in California, what do those trends look like because certainly the historical perspective is relevant to our efforts to try and forecast what we think is going to happen over the near and longer term.

And we'll look at some of the primary

drivers that cause crude oil imports to increase and we'll also look at some of the uncertainties associated with our forecast. There are some issues out there that give us a bit of pause and may throw some -- you know, a significant amount of uncertainty into the results that we'll present.

And some of those would be some of the next steps. This work is not finished by any means. We certainly welcome feedback, constructive criticism because we can always do things better, so that's part of the purpose of why we conduct these meetings.

California is -- the petroleum infrastructure is what we've been looking at, especially over the last couple of IEPR cycles, the main parts and pieces are the refineries, the main hub of the production, imports, crude oil, gasoline components, diesel, jet fuel, rail imports of ethanol and seasonal movements of LPGs, propane, butane in and out, and the distribution from about 60 terminals by tanker trucks to get all those fuels to the 10,000 retail stations throughout California.

This is more of a regional flow. The

purpose of this is to illustrate the interdependence, if you will, of the western United States in terms of petroleum product flows. Washington State refineries do provide petroleum products to California and vice versa to a lesser extent and a lot of that has to obviously come by water.

There are no pipelines that connect California to adjacent states that receive petroleum products from those adjacent states. Those pipelines are one way. They originate in California and they go to Nevada and to Arizona.

So the way we primarily get additional imports is by marine vessel and that has to come through a marine terminal and those are in San Francisco Bay area as well as Los Angeles Basin which includes ports of LA and ports of Long Beach.

This is a little bit more detailed breakdown, illustrates some of the petroleum product pipelines in black and one of the main take-aways is that Northern California and Southern California are not connected via pipeline. Electricity, yes, but there's a separation here at the Tehachapis, so there is no connection.

So if you want to get additional petroleum products from Northern California down to Southern California, it's by marine vessel. And so there is basically a net flow because the production in Northern California is greater than the demand and demand in Southern California is greater than supply and so there's a normal flow that occurs from north to south and there needs to be adequate barge movement and assets for that.

The pipelines, we do supply Nevada through a pipeline going to Reno, northern Nevada, and to Las Vegas which is the lion's share of the Nevada pipeline exports as well as pipeline movements into Phoenix and on to Tucson in Arizona. And I'll talk a little bit about the numbers and why we care about the pipeline network and what relevance does that have to imports of transportation products for California in a while.

And then there's a pipeline that does come from western Texas, El Paso, that goes into Phoenix and Tucson and that's been expanded recently and I'll have some slides on that topic.

So let's talk about crude oil. This is the primary focus of this first presentation.

Where have we been and kind of where are we going. Well, in more near term, over the last 21 years, we see that crude oil production has been declining which is pretty obvious from this stack bar graph and the main components are you're seeing basically a 39 percent decline in California which is the lower green line and Alaska production has declined more steeply, about 60 percent since 1986 -- between '86 and 2006, and the rest of U.S. production has declined by about 35 percent over the same period of time.

So now let's take a look at -- you can see the relative importance. California's numbers are relatively small, but in the grand scheme of things in total production.

Now let's take a look at those California numbers in a little closer detail. So California is basically broken into onshore production and state waters -- state offshore and if you get far enough offshore, then you're going to get into federal waters. And that's what we call federal -- outer continental shelf or OCS as the acronym has on the left here.

And you do notice there is a -- sort of a bump up in that federal OCS production. That's

Point Arguello came online and production ramped up rather steeply and then it fell off rather steeply -- lot steeper than the certainly the people that invested in that project initially anticipated.

But -- so if not for that bump-up in the federal OCS, the decline rate would have been steeper than it is already. But California like the U.S. production is declining. We have very mature fields. We've been exploring for crude oil, initially digging shafts into the side of hillsides or digging out of pits of basically tar, going back quite a ways. So we do like to get an historical perspective on things and the more historical, the better.

So this shows California production going back to 1876. There was about 12,000 barrels of total production between 1866 and 1876. I wasn't around, but people like maybe Joe Sporano were here. They might have some notes they could help us to fill in the blanks there.

So what's quite obvious is yes, this does go up to a peak of 424 million barrels in 1985 and since that time has been declining. But you think wow, I mean drilling for oil for 131 years or 140 years and we produced an awful lot. Oh, about 20 billion cumulative barrels, so that must be a lot -- 11 months of global supply.

So that's a lot of production. That's a lot of wells. That's a lot of effort and yet it's 11 months of total supply, current level.

So kind of puts in perspective of how much crude oil the world is using and how little we actually do produce even though we're the biggest -- one of the biggest states.

These are just sort of a rundown of the numbers I've already talked about during the slide presentation, so I'll just -- I mean they're there for completeness and we'll continue on and look at taking that historical information and looking at some of the decline rates.

Well, it's just really going to, you know, be a good indicator of future trends. Well, it has been for a decline in mature crude oil reserves. They do have a standard increase and then a decrease, a decline, you know, Hubbard's curve, what they call it, goes up, comes back down, bell-shaped curve, and no surprise whether that's in, you know, Florida or Mexico or California or Alaska, you're seeing the same sort of slope -- or shape -- excuse me.

So looking at some of the information, we go over a little bit longer time period, '91 to 2006, we see an average annual rate of decline of about 2.2 percent.

Now, looking at a little bit more recent perspective, it's about 3.4 percent since 2003. Annual rate of decline, every year, another 3.4 percent lower output from California fields even though price is double, triple, quadruple what they were in 1998.

So it's rather significant. Technology is not necessarily going to save you. It's sort of geologic certainty of a depleted field. You're only going to get so much blood out of the turnip. So that's -- these decline rates are expected to continue.

Now, we've used two different decline rates because we don't just like to have a single point forecast of here's our forecast and that's it. Well, we do like to have scenarios. We like to look at, well, what's sort of a low import crude oil forecast and what's a high import and I'll talk about what those factors are and we have done that and we will also look at some additional uncertainty factors as maybe some deviations of our current forecast.

But you might ask, well, over a longer period of time, that decline rate isn't as steep. Well, remember, back to my slide on California where the offshore production bumped up. That makes that decline rate less steep than it would have been otherwise. It would have been more proximate to the 3, 3 and a half percent per year, even over that longer time period.

So declining imports, what does that mean? Well, the refining capacity for processing crude oil isn't declining. In fact that's going up at a very gradual rate. So that means as our California production continues to decline, more barrels over the water. There's no pipeline from a crude oil producing area that goes into California.

So imports are going up. Since 1995 -- I think this lower point up here which I guess -- there we go. There's been about 25 percent increase in the number of water-born imports between 1995 and 2006. Over that same period of time, Alaska, the upper line, the dark green line, those imports have declined by 60 percent since

1995. So rather significant but not surprising, Alaska's production, as you may recall, since '86 has declined by 60 percent and as the supply of Alaska crude oil gets scarcer and scarcer, it will find a home closer to Valdez, meaning it will find a home in Washington State refineries.

They're heavy users of ANS (ph). They'll continue to do so, and then there'll be, you know, less of a home further away you get from Port Valdez because refineries, they have a marine terminal, can import crude oil from anywhere they want as long as it's within a certain degree of quality for their refinery operations.

So naturally foreign imports continue to grow of crude oil and they've been growing at -- that lower line's been growing at a rate of about 1. -- I think it's 16 percent per year. Yes -- growth rate in foreign imports of crude oil to California berths and about a fivefold increase since 1995.

So rather significant, but the total for a marine terminal doesn't care where the crude oil came from. It just cares about the quantity of crude oil going across a particular marine terminal. That is the primary factor.

MR. GEESMAN: I wasn't clear, Gordon, what the number you were using was in terms of the annual growth rate in imports.

MR. SCHREMP: The annual growth rate -- I'll get to that in some latter slides if I could defer, Commissioner. I will cover both the incremental crude oil imports as well as the percent change in our forecast.

MS. JONES: And, Gordon, there's a bump in 2005 in Alaskan, it appears. Do you know what that's from?

MR. SCHREMP: There is -- you do notice that there is a -- you would think this would be smoother, but there are some other factors that can cause year-to-year variations and one thing is -- and I mean -- is refinery operations is you can have major upset that takes a crude unit down for a couple of months.

And so you could see variation from year to year. You could see a very heavy maintenance schedule on crude units. In fact that is what we believe is happening in 2006.

Why are the imports down if California crude oil supply actually decreased. Well, in part, crude runs to California refineries were actually lower than they were in 2005. Primarily heavier than normal maintenance on crude units as well as, you know, a number of scheduled -- unscheduled -- unplanned outages. So that caused crude units to go down.

So we do see this, but over time, you'll see a general trend especially when you overlay the decline in California source on top of that.

Those are the numbers I've already gone through. That's -- like I said, 16 percent per year increase in foreign import levels to California berths.

One of the main drivers, pretty obvious. I've been talking about the lower box on the left and that's our decline in California sources of crude oil. Well, there's another driver for imports of crude oil and that is the ability of the California refineries to process crude oil. That's not static. That does gradually increase over time and we refer to that as -- a phrase that the industry loves -- refinery creep.

And so that goes up at about -- it depends on -- there's a couple different types of refinery expansion or gradual creep. That's for the processing of crude oil which we refer to as distillation capacity expansion and then you look at the ability to increase the process units that take the partially processed crude oil and turn that into other components, gasoline components, jet and diesel.

And those process unit capacities have also been increasing. So if California refineries continue to expand at historical rates, between half and 1 percent per year, that will be incremental demand for crude oil.

So couple that with declining sources of California supply and the result is incremental imports. And we care about forecasting crude oil imports because we care about adequacy of crude oil infrastructure. So that's the ability to take ratable volumes through marine terminals as well as adequate supply of storage tanks for the crude oil you're receiving over time -- the incremental crude oil you're receiving over time.

So you need both the marine terminal and you need additional storage tanks. So that's what basically our analysis will culminate in is quantifying both of those variables.

So this is basically our lower end of our crude oil import forecast and the lower dotted line is the California source of crude oil and the upper line is the ability of California refineries to process crude oil -- their capacity if you will.

And comparing to 2005, we see that come 2015, we're looking at an additional 81 million barrels of imported crude oil and by 2025, we're looking at about 151 I think if the math is right there.

So rather significant import levels from -- if you put that in perspective, from -- in 2006, we imported about 401 million barrels. So that's a sizeable increase.

But this is conservative, if you will. We're assuming just a .4 percent increase in that ability to process crude oil, distillation capacity growth, and we're assuming that conservative 2.2 percent decline in California source.

So now change the assumptions, I change my answer. That job opens up. If we look at that 1 percent growth in distillation capacity expansion and we look at a steeper decline rate of 3.3 percent. Now, the numbers are larger obviously. So those two factors are driving those numbers to get bigger.

And so now you're looking at by 2025, you know, another 266 million barrels. So that's a lot compared to the 401 we're importing today over the water.

Once again this slide is here for just completeness. It's the numbers I just spoke to for the slides, and so I'll go onto the next.

Putting them in a table can help when it comes to answering questions of well, what if you use a different growth rate for refinery capacity. All right. We'll go there. We'll use the conservative one on the top and the higher growth rate on the bottom and here's kind of the in-between rate.

And then we look at a decline rate of 2.2 for crude oil production in California and on the far right, a decline of 3.4.

So mix and match, midterm, long term, and you get only 81 million incremental or you can get up to 138 for 2015, and longer term, you look at a low number of -- incremental 151 million and 266 by 2025.

So change the assumptions, the analysis and the results will change and so greater volumetric throughput, incremental input -- throughput on a daily basis, and greater needs for additional storage tank capacity.

Now, this is California. Does the region matter? Yes, it does. 60 percent of all of the crude oil imports to California over the water go through Southern California ports, Los Angeles and Long Beach. So this takes a look at our forecast for that subregion, the more -- I think the more critical subregion of the two.

And this just -- the same approach. We break out distillation rates on the left and crude rates along the top and you get ranges of 49 to 83 million incremental barrels of crude oil to Southern California and you were looking at say 240 million in 2006.

So then you're looking about 2025, larger numbers, 91 to 160 million incremental, once again to the base of about 240 in 2006. So that's a rather large increase especially by 2025.

And transition to the next slide. So what can we -- what conclusions can we draw I think at this juncture in our work and recognizing we're early on in the process to receive, you know, constructive criticism and the import to the record, You know, that's a very valuable component of this entire process.

So we do seek that out and we do encourage people to provide us their input. But we're seeing continuing decline in the fields. We don't see that being arrested through very high prices, additional drilling activity. There is a slow continued decline.

We're seeing -- we are seeing gradual expansion in refinery capacity. It's been able to be performed. That's when companies look at a doing a major project at a refinery, say, every five years. Their engineers always come in with, hey, you know, for a few dollars more, well, 10s and 20s and $50 million more, you could do this little tweak here and we'll take that bottleneck out and it pays for itself in the grand scheme of making our refinery more economical, more profitable.

So those projects are always considered, but they're in competition with projects for the multi-nationals in everywhere else and all the other business activities they're involved in. So depending on the -- you know, the return on investment, the ROI, those projects may or may not get approved.

And so they always have good -- have great ideas, but they don't always get approved internally. In fact they rarely do. But certainly this is a valuable market in California relative to other U.S. -- or global refining centers and very profitable, so I think now -- and I'll talk about this in my subsequent presentation, but we're seeing more projects that people have proposed for expansion in California refineries just because I think they're done spending 5, 6, 7 billion dollars in meeting new fuel regulations and now there's an opportunity to spend additional capital to do economic projects and expansion projects in the U.S.'s most lucrative market.

So we are going to look at -- and part of our conclusion is that we believe those numbers translate into at least one large import facility being constructed in Southern California and if you go longer term, higher end of the import forecast -- by the end of that long-term projection.

Northern California, we do see the equivalent of one additional large crude oil import facility being constructed, but there's a difference. The two areas are significantly different.

Southern California does have some prime deep water berths that ships could pull up into, very large crude carriers, VLCCs, with 2 million barrels of capacity and economically deliver crude oil to Southern California.

Northern California not so. The reason is you come through -- into the San Francisco Bay. It's shallower. In fact if you get past the Richmond refinery, there is a very shallow spot referred to as Pinole shoals and basically that's rock and you're not going to get that down to 80 feet. That will never happen. There'll be saltwater intrusion in the bay and so the bay is limited in to the size of the vessels that they can get.

So we don't think that the solution or the changes by industry to import additional crude oil into Northern California will be the same as Southern California. It'll be more of sort of incremental increases at individual existing wharfs unless of course there is a project to put a large facility prior to reaching those shallow depths of the Pinole shoals.

But no one has proposed anything seriously. There's been considerations in the past.

So why is all of this important? We think that the clock is ticking. These trends are clear. The trends are not changing. We see more import needs and we don't see any changes going on in the infrastructure.

We see efforts underway to -- with proposals on projects to expand crude oil import facilities and we -- you know, I think David Wright will talk to that topic in a little more detail following my comments, but this inaction or inability will create a problem.

You know, if the refineries don't have enough crude oil to process, then obviously they'll produce less fuels and if the demand doesn't change, then therein lies an area of concern.

So that's why we're looking at it. That's why we'll continue to look at it. This is not new. We highlighted these concerns back in 2005 and they'll be rehighlighted, but with additional information brought to bear compared to two years ago.

There is uncertainty with any forecast obviously and this is no different. One of the biggies is AB32 and that essentially is a law passed this year that requires reduction in greenhouse gas emissions from stationary sources, specific classes of stationary sources like power plants, cement kiln operations, and refineries.

Now, we do not know and in fact I'm sure the affected industry does not have a clear set of regulations because they're supposed to be developed I think over an 18-month process by the Air Resources Board and it's too early to tell what that means.

Can I -- you know, can I still maintain or even increase my capacity at my refinery in California and buy offset somewhere else? Cap and trade, can I do that? Yeah. That's being considered. That's on the table.

So we don't know how all this is going to work out, but it is possible that one of the ways it could work out is that the refinery capacity growth rates that we have assumed may be erroneous. Maybe in fact we're looking at a capping of that distillation capacity at

California refineries and possibly even a decline.

But too early to tell. Just noting that this is a degree of uncertainty inserted. We most likely will not have any answers, but we will discuss this in our report as a degree of uncertainty.

And I think one other thing I wanted to touch on, if that happens -- if crude oil processing declines -- capacity declines, that doesn't change the demand for petroleum products. So whereas the pressure may be eased a bit on the infrastructure to import crude oil, less imports than we forecast, the forecast for transportation fields which I'll discuss next will be even higher if capacity in California for processing crude oil declines because they'll have to import more to make up for the loss in output from the California refineries.

So it doesn't -- you don't just get a reduction in total imports from both the crude and the fuel side. They counterbalance one another.

There are efforts underway. Certainly with crude oil at 60, 65, $70 a barrel, I go out on the weekends looking for it myself because that's a pretty lucrative business.

So people are looking at maybe expanding some offshore development from existing platforms. They already have a platform in -- more directional drilling, more active directional drilling. That does go on.

Looking at long reach drilling from onshore into those offshore fields from an onshore site. Certainly you're not putting the marine environment at the potential risk by doing onshore development and even injecting say CO-2 as a sequestering process, but injecting that into the crude oil fields to build up the pressure and then get a little bit more crude oil out of existing reserves.

These are all technological advances that continue and can possibly affect the decline rate that we have forecast for California fields.

MR. GEESMAN: Is the discussion of CO-2 injection limited to those fields where they currently inject steam?

MR. SCHREMP: I think we might have somebody here from BP, but BP's proposal to actually pipe CO-2 associated with hydrogen production in Los Angeles Basin to the Kern County fields, I think they've targeted -- Occidental's targeting specific fields that may be most appropriate for CO-2 injection.

I don't know if those in fact are some that currently receive steam injection or water flood injection. I'm not familiar with the geology of the fields and which fields might be most appropriate, but it's possible somebody here might have an answer to question, but I don't know, Commissioner.

MR. GEESMAN: Yeah. I guess the concern I'd raise would be economic. If you're looking at a scenario that would enhance production from California wells, if you're broadening the category of wells that could benefit from injection, that may be one thing, but if you're simply replacing steam injection with CO-2 injection, I would presume that there's a cost to be paid for that.

MR. SCHREMP: Well, and that's a good point. If one is looking at, you know, continually increasing natural gas prices and you're -- that's your main energy input to create the steam to flood the field -- and you say, well, gosh, you know, if we have a pipeline here, the economics of CO-2 sequestering -- just trading off and still you don't get any incremental crude oil production, that's a good point.

And I think people from like the California Division of Oil and Gas, they have people that have some pretty good expertise in the existing fields and what's going on and so -- that's certainly an area we've tapped into in the past and we encourage their input as well and we'll be directly seeking out to try to respond to that question.

Okay. Next steps belies that one is to look at Southern and Northern California, but then burrow down a little bit deeper to individual marine terminals, and we're going to be looking at a survey of the industry, which they always love it when Gordon sends them another survey because they have so much free time, it helps fill the void.

But -- that was sarcasm for those that couldn't see my face. So this -- the whole point of this survey is to -- simply put is how much is going through your marine terminal and how much more could you run through the terminal.

Now, I want to draw a distinction between say a chemical plant, a refinery, a power plant and say well, we're utilizing out plant at about 98 percent capacity. Oh, you got about 2 more percent you could squeeze out. Oh, not necessarily because I'm doing -- I do plant maintenance every year and I take it down, so when you average out over the whole year, I do 95, 96 percent.

Okay. I'm in a marine terminal. Well, I get 20 -- 25 days out of the year -- of each month I have a ship here offloading crude oil or petroleum products or loading something. My berth is occupied 25 out of 30. Well, I can do the math. What's 5 -- oh, you got -- divide by 30. Oh, good. You could get up to 30 days.

Well, not so fast. Ship movements is not a precisely timed mechanism like Amtrak. Or maybe that's a bad example -- like some other -- because you encounter changes in your anticipated voyage time. Maybe you encounter high winds and high waves and so you slow your vessel down. That's for safety purposes. That's a good thing.

Maybe you're bringing cargoes in from the U.S. Gulf Coast to California and you have to go through, yes, the Panama Canal. So get in line unless you want to bid online to try to move your space up in the slot, but there's some uncertainty there that could add days to your voyage.

And so when your ship will exactly show up at a marine terminal isn't precise and it never really will be. So they have to allow a little time.

Now, you would think, well, it'd be like going to the airport. I'll -- I can look out there and I'll see them lined up ready to get the next one in the queue. That would be very efficient for the marine terminal, but not for the guy who's renting the marine tanker. Why? Because it's a taxi.

That guy -- the ship captain will sit out there day in and day out, week in and week out. He doesn't care. The meter's running. He's getting paid. Sitting, moving, unloading, it doesn't matter. He's getting paid.

They don't want to pay (indiscernible) can be, you know, 30, 40, $45,000 a day. They don't want to pay to have a taxi cab sitting there.

What they want to do is arrive, pull up, do the paperwork, unload, do the paperwork, and leave. That's what they want to do. That's the most efficient.

So you will never see these berths occupied with a ship every single day. That won't happen. So we want to understand that there's some sort of science and art in looking at what that sort of spare capacity is and one way of doing that is looking at what sort of peak offloading events have occurred at that facility. And even then, that might be a bit high because that's not sustainable. Why? Because there may have been ships sitting on the queue that allowed them to maximize during that particular month the number of vessel calls they got at that berth.

So this -- so we're trying to capture how much additional spare capacity there might be and I think maybe Dave Wright will even talk to this and some of the experience they have in the existing ports, that there really isn't a lot.

But we want -- try to better quantify that rather than what we've heard from companies. So there's a clear need we believe for imports of crude oil -- additional imports and a clear need for expansion of existing infrastructure.

Timing -- timing is very important because these projects take years -- not only years to develop to get the permit -- and Dave Wright will talk about that -- but also could take a significant amount of time to build to they're ready in time when you're bumping up against your limit of what you could bring in and you are looking at now running your refineries at slightly lower rates.

So that's a potential consequence of additional delay in getting these expansion projects up and running. So we will be providing additional information along these lines in advance of our July 12 workshop and we'll try to do it enough in advance so either Jim or I don't stand up there and apologize again for -- sorry didn't get the material till just a couple days ago.

So we're going to try to get that out -- correct ourselves and get that in advance so people can actually consider that.

So the venue will be different. It won't be here. It will be in Southern California. It'll be at the Port of Los Angeles, their admin building in San Pedro. And so we'll -- that's our next port of call if you will.

So I think -- I just want to -- in

summary, these are some of the numbers I spoke to, the 81, the 138 million by 2015 and, Commissioner Geesman, so that's about 20, 34 percent increase compared to -- and that's 2005 level. So it's slightly less for -- or actually it's about the same for compared to 2006 because imports over the water went down just a little bit, by 6 million total barrels.

I want to stress, one point is that reducing our demand growth for traditional fuels, jet, diesel, and gasoline, will not have an appreciable effect on crude oil imports. Why? Because those are different drivers. Crude oil decline and distillation capacity growth are driving imports not demand for transportation fuels.

Now, if you take that to a much, much longer time horizon, let's say, demand increases then tails off to a point where, wow, we're way below what the refiners produce, then obviously you'll see a reduction in crude oil capacity.

You'll actually see some of the high cost providers fall out of the marketplace. We've seen this in the history of California refineries. The less sophisticated, the high cost provider, they're the ones that exit this market.

You know, back in '80s, 90s when carb regulations were -- guess they went into effect in '96. So we expect that to continue if in fact demand does drop off, but what would happen first is that imports of transportation fuels would decline.

The California refiner is getting the value added by processing crude oil and in making transportation fuels and selling them at a premium in this -- the U.S.'s best market.

So the first thing they'll do, they won't reduce crude runs and keep importing the same amount of gas components, they'll reduce imports. So that's the first thing -- or reaction you would see to demand, you know, peaking and then starting to decline -- imports of clean products going down.

So be happy to answer any questions on the crude oil import forecast topic.

MS. GREY: Hi, Gordon.

MR. SCHREMP: Hi, Gina.

MS. GREY: I'm not Joe Sporano, but I have gray hair and I've been around for a while. I'm Gina Grey and I'm with WSPA.

I think overall we probably would agree with a lot of the information that you've provided. I think one of the things that we feel is like a 500 pound elephant that's in the room that hasn't been talked about is energy policy. How does that impact this whole scenario.

And I think our contention would be is that there's a lot of state as well as obviously national energy policy that is potentially suppressing the amount of domestic crude oil production. So I would just offer up that I think our upstream folks would be very interested in meeting with you and discussing that and seeing if there's something you can build into this analysis that addresses that point.

MR. SCHREMP: So in other words, go a bit beyond the part of the slide where I talk about other technology --

MS. GREY: Correct.

MR. SCHREMP: -- talking about --

MS. GREY: Energy policy.

MR. SCHREMP: -- potentially opening up other areas --

MS. GREY: Correct.

MR. SCHREMP: -- that have the income --

the potential --

MS. GREY: Right.

MR. SCHREMP: -- to increase crude oil supplies.

MS. GREY: Right. Getting more blood out of the turnip as you said. Thank you.

MR. SCHREMP: Okay. I believe we have a question on the phone? I believe I was so thorough I addressed their concerns.

Well, if there are no additional questions, I can get to the next presentation, if that's okay? All right.

So by now, you already know who I am, so we'll skip this. This presentation covers the other component -- the import forecast for transportation fuels. And what do we mean by that, well, we mean gasoline, gasoline components. We mean jet fuel, diesel fuel, and we also mean imports of alternative fuels.

I think there was a question earlier about, well, are you guys looking at additional imports of say ethanol for E85. Well, not E85 maybe specifically, but we are taking into account a forecast for ethanol demand as part of this IEPR cycle with regard to impacts on alternative fuel import capability.

So there is an infrastructure for that, primarily rail, but, for example, going from an E6 for about 6 percent ethanol in gasoline to 10 percent ethanol in gasoline, that's about a 67 percent increase in import -- or excuse me -- ethanol use and the amount of imports has to do with how much domestic or California capacity you have and how much your gas demand has changed relative to today, and I'll talk about that.

But, yes, to answer to that question, yeah, we are going to look at alternative fuel imports as well.

So same approach. We look at the primary drivers that cause us to import transportation fuel products and we also look at -- and some of those drivers are something new and I'm going to get back to, yes, those -- that pipeline map and why that's important and why we care about exports to neighboring states.

And I'll sort of finish up with, you know, what we expect to do out of this forecast. We're not as far along as we are in the crude oil import forecast, so I'm primarily talking about what we plan to do. And this is in advance of our

July 12th workshop -- next workshop on the subject.

And I'll talk a little bit about containers versus petroleum infrastructure because that is a very important factor in the additional pressure being put on existing petroleum infrastructure as well as competition for spare land to site new storage tanks and new import facilities.

This is the only repeat slide I have, but I wanted to show this again because the region that we look at to calculate imports of fuel are mainly a three-state region, California, Nevada, and Arizona.

Well, why didn't I do that for crude oil? Because the refining capacity in Nevada and Arizona is less than that in California. Well, it's -- well, it's basically zero. So that doesn't matter, unless of course there's a new refinery built in Arizona, and I'll talk about that.

So it's a three-state demand region, and why? Because we primarily provide the bulk of the petroleum products to Nevada and Arizona, about 100 percent to Nevada and about 60 percent to

Arizona.

So as their growth increases -- population growth rates in Nevada and Arizona, some of the highest in the United States, their demand follows population growth quite closely. Jet fuel, demand growth in Nevada and Arizona -- primarily in Nevada -- is even higher because that's driven by tourism not people living in Las Vegas. But the tourism is a big driver for incremental growth in jet fuel and Vegas is booming is you ask Steve Wynn.

So transportation fuels, these are jet, gasoline, diesel. Where are we? We're about 24 billion gallons of demand in 2006. Most of it gasoline. About a billion in alternative fuels. Most of that is ethanol. That's the 951 -- 951 million gallons.

And then we have diesel fuel in the blue and the purple is jet fuel and they're fairly close, about 4 billion gallons each. So in total about 24. And that's 2006.

One interesting note for 2006 is that demand for gasoline apparently dropped for the first time since 1991. About a, you know, .5, .6 percent decline compared to 2005. So it may be that actually high sustaining prices did actually have an impact on people's discretionary driving capability and vehicle preferences and things of that nature.

So our assumption that demand will continue growing and despite even higher prices, you know, that's certainly -- this most recent piece of information brings some debate to that perception.

Closer look at the billion gallons of alternative fuels. You'll see obviously ethanol, but there is some natural gas and we do see some biodiesel and that's about 20 to 25 million gallons on 2006. A little bit of propane and hybrid and neighborhood electric.

The natural gas and hybrid electric are basically petroleum displacement. So obviously you don't consume gallons of electricity. So -- but that's our way of showing it on this graph as an alternative contribution.

So just a little perspective. What did we do last time? Or more importantly, what did we not do last time and why we're updating it. I think the significant update is we didn't look at alternative fuels. We just basically give cursory note that, yeah, there's a lot of ethanol and here's the number.

And we did not look at the neighboring states. You go, oh, well, that's no big deal. I mean they're small. They can't do a lot.

Well, actually if you include the neighboring states, you could increase our previous forecast by anywhere from like 40, 60, or 70 percent or higher of incremental imports. Rather significant.

MR. GEESMAN: Let's also recall the last time the Commissioners involved expressed an extreme amount of discomfort with the fact that you had not been able to include the neighboring states.

MR. SCHREMP: That is correct. I remember the discomfort. So not to repeat same mistakes. So we have a lot of focus, as a former colleague says, focus like a laser on this issue.

So we are like everything else associated with our work, we're looking for input from stakeholders, and one of the big stakeholders obviously is the company that operates these pipelines. That's Kinder Morgan energy partners. So we've received information in the past and we look forward to receiving some additional import along -- what are they seeing in the neighboring states for growth rates.

And more importantly when -- and I'll talk about this -- is what's going on with regard to the pipeline infrastructure because Arizona can receive petroleum products from two different directions. So if you change capacity in the pipeline on one side and more supply comes from the east, then that takes a little bit of the burden off of California refineries from the west. So that's important.

So we're going to be looking at that. Once again AB32, we don't know. It's too early how that'll affect refinery output. Less output of transportation products means even higher imports of transportation fuels.

So it's too early to tell and it's unlikely we'll be able to make any definitive conclusions in this round of the IEPR.

Taking from Jim's boxes he had up on his one slide -- these are the main components that we do look at and the one that was missing last time but won't be missing this time is this neighboring state, and we care about what Jim and his folks come up with for California fuel demand because, you know, I wait to see what those numbers are because they're going to affect my imports of transportation products and it's multi-state.

It's the three-state region I discussed. And then just like for crude oil, what are the refineries doing with regard to their output of gasoline, diesel, and jet fuel components from these other process units they have?

You may appear like, oh, FCC -- unit or alkylation unit, well, those are big time gasoline component producing units at a refinery. Very important.

So is there some expansion in that area? Yes, there is. And so over time, we've seen a growth rate of about .5 percent per year in that process unit capacity and that mean you could eke out additional transportation fuel products. So we do care. That will affect the forecast.

If it's flat, more imports. If it's, you know, even higher than we anticipate, little bit less imports in the forecast.

So all of those combine to give us a forecast for transportation fuel imports and then we just have to look at, okay, regionally where they want to go and what kind of existing capacity as well as what kind of existing storage capacity expansion do you need. So both throughput and additional storage tanks and you'll be regional.

So parallels the same approach we used in the crude oil assessment. A couple of different driving factors for this.

Now, it's also important to note that as you saw with the crude oil imports, lion's share goes down to Southern California. Well, for transportation fuels, even greater. 80 percent of imported transportation fuels are through the ports of Long Beach and Los Angeles.

Why? I told you before that production in Northern California is greater than demand and there's a net flow down south. So that's why the imports want to go down there and we expect that not to change over the forecast -- at least the near-term forecast period.

So that's what will culminate in in our game plan here. That's the approach. Fourteen refineries in California and I guess a 15th possibly soon producing California compliant gasoline and diesel fuel. Three main centers, Northern California, Bay Area, Southern

California, Los Angeles Basin, as well, as the Bakersfield region. So those -- that's where the fuels are produced and the lion's share of our demand is met from those facilities.

But their output has not kept pace with demand. So demand's growing at a faster rate than they can produce additional fuels, therefore growing imports, and that's what we've seen. So same story for -- as we've seen with crude oil.

The fact is we look at -- you know, how can they increase production and that is they can process additional crude oil and that's the distillation capacity growth rate assumption, .4, 1 percent, you know, depending which one we use, more transportation fuels. More crude oil processing, more transportation fuel output.

And then process capacity, you know, if that's growing instant rate, that means more transportation products produced internally and less need for imports. So those are important trends as well as a forecast of trends for both of those capacity growths.

And I mentioned utilization rates or are you operating 100 percent of the time or a portion of the time, you know, what are you doing. Well, for refineries, their utilization rates for crude oil distillation are about 91 percent over the last I think ten years. And that's because they have to do plant maintenance. They have unplanned outages and so we'll never been 100 percent, but some lesser amount.

So we assume as part of this analysis that that sort of utilization rate remains the same.

Now -- so if somebody wants to -- you know, if there's some good information on -- okay, well, actually because technological advances, we can -- you know, we think that's going to go up to 92, 93, 94, please let us know because that would affect the assumptions we make for our forecast for those purposes.

So all those, as I mentioned before, is refinery creep and we will continue to look at near-term historical trends and translate those into forecasts in looking for other input on maybe different methodologies to use for this part of the work.

Expansions -- now, this is not gradual -- you know, I'm doing -- so I did a little debottlenecking here, over there, and I got -- eked out a little bit more production. No. I'm talking about making a whole -- a whole lot more increase in my out put of fuel.

There are some projects underway. I mentioned that refineries have been very busy spending lots of billions to comply with changes in fuel specifications -- gasoline -- low sulfur diesel to name the top two.

So now that's essentially done. We don't see any major -- except for the revised predictive model and that's how California refineries make gasoline. They use a spreadsheet linked to their linear program and California Air Resources Board must make changes to that model to compensate for the fact the use of ethanol has increased evaporative emissions into the environment which we refer to permeation.

So the Air Resources Board in the process of developing that regulation. They'll have a hearing down in Fresno on June 14 before their board to propose changes for the industry and we believe those changes will affect the industry.

We do believe there'll be investment that -- you know, this early stage, we're still conducting meetings with them and performing some internal analysis, but we're looking at probably between 1 and $1.5 billion in investment for the industry collectively.

We're also looking at, as Jim Page mentioned earlier, 5 to 10 cents, that's probably a pretty good estimate for incremental production cost as well as the impact on the price of imported components.

Now, when you're importing gassing components, you want certain sulfur levels and certain octane levels, well, now these changes that we see in the predicted model and how refineries will make gasoline after the revised predicted model, those changes will be such that they want to have lower, lower sulfur -- lower sulfur for your import components, imported gasoline, as well as lower sulfur in your refinery operations.

All of that will be more expense, more value placed on the -- on scarcer components and more production cost increase. So 5, 10 cents is not an unreasonable estimate at this stage of the analysis.

So -- but back to the expansion

projects, obviously if you put in -- I make a third more fuel at my facility than I -- well, that's not a gradual expansion. That's sort of a one-time bump up in supply. That will have an effect on imports obviously, on our import forecast.

So we plan as part of our -- I think our low forecast scenario, we plan to at least put these facilities and their planned expansion on that contract in our time horizon, show that as incremental supply from internal sources.

So that'll be important and that will obviously change the forecast. So this is something -- frankly this last time, these kinds of projects weren't really on tap. Now they are and now they're actually in the -- the ConocoPhillips in Rodeo, their expansion is probably the closest. They go before the Planning Commission tonight for approval of their permit to construct. So they may receive approval this evening. We'll see how they vote down there.

So they're the closest. Big West is having expansion of the Bakersfield refinery. They're in the permit process. Tesoro has, you know, publicly announced in their acquisition which we anticipate along with them closing this month for the purchase of a Wilmington Shell Refinery.

They have publicly stated they will increase the amount of clean fuels being produced at that facility. And so we are aware of projects. There are some other ones that -- not necessarily public at this time, but are under consideration, so there may be more as we go through this process of analysis over the last month.

So any input is appreciated on those lines as well. So certainly how much of an increase and when will affect our import forecast. So we plan to have that built in.

And once again there is so much uncertainty because these projects especially more recently have come under extensive opposition -- primarily local -- to any increased activity at any existing California refinery.

And so understandable from the people that live in close proximity, but it's something that we -- I think everyone recognizes and is a factor in maybe decreasing the probability of some of these projects actually being constructed.

So there is uncertainty even though they -- even though they have a permit, doesn't necessarily mean that ultimately gets constructed.

Demand growth -- these are almost no-brainers. I mean obviously Jim's forecast is a big driver to how much -- you know, how much our refinery is forecasted to produce and how much is our demand and that will play into the import forecast, both high and low cases.

Alternative fuels. About 6 percent of our gasoline is ethanol, primarily imported from domestic ethanol plants in the Midwest by rail. Southern California primarily has a -- what we call a unit train ethanol import facility. That means 90, 100 cars at a time can pull in, split them up into 50-50, and offload them almost all at the same time and then out they go.

So very efficient, very cost effective, and what's important increasingly rail congested environment, which rail is, and I'm preaching to the choir to all those that use rail.

If it's a unit train, story's far different. Priority clearance on the rail by BNSF or union. They priority clear those movements. Coal, grain, ethanol. Obviously because they have a vested interest in getting the commodity where they say it is as efficiently as they claim they were going to when they went in partnership with this import facility in Southern California.

So they came through -- the industry came through and that infrastructure works very well. So very impressive and the cost have come down compared to other forms of rail. Manifest car rails. I have -- you have three cars mixed in with another hundred. Well, they'll go to siding somewhere in California. Then some other rail company will take them and they'll get them to the refinery that needs them. That's a more difficult movement. That's a problematic movement at times depending on when they're congested.

So most of the ethanol we're looking at in Southern California is unit trains. We don't see a problem there.

Northern California, some unit train movements in here. A couple of rail offloading facilities, but it's not -- it's structured differently. There's more manifest rail cars in Northern California.

Marine movements. There is the ability to bring in ethanol from over the water.

Primarily that will be from say Brazil or some Caribbean countries and there is the facility to offload. At Northern California, the Selby facility, operated by NuStar, and in Southern California, a couple of the marine terminals can import ethanol.

So we've seen that happen and depending on the demand and the various prices, you'll see changes in the imports over the water of ethanol.

Last year, I believe we received all -- you know, China was an exporter to California. Kind of unusual. They actually import ethanol, but it was in their -- logistics worked out just right that ethanol came to California.

And we received some Brazilian and Caribbean material. So we expect that to continue as time goes by especially after looking at a transition from E6 to an E10. Certainly an opportunity there. So there's already existing infrastructure. That's good news, but like the ability to get ethanol to those distribution terminals because ethanol doesn't go through the pipelines, it's blended in the tanker truck before it goes to the service station.

So you have to get to those 60

distribution terminals primarily by tanker truck. So going from E6 to E10 is about a 67 percent increase, assuming gassing demand stays the same and so that's a rather significant increase and we already understand to go to the higher ethanol levels, the distribution infrastructure will have to be modified and that will take at least a couple years if not a little bit longer using permits -- permit timelines.

And it's also important to point out that the refineries will need time to make modifications. I mentioned 1 to $1.5 billion. Well, you don't do that in months. That's measured in years and the steps are I do my engineering to figure out what equipment to order and now I know what to put in my permit and in the CEQA process. Now, I can buy my equipment and I'm going to install it and test it and so that's a multi-year process.

So if anyone thinks -- you know, I see in the trade -- in the popular press, oh, yeah, we could, you know, quickly go to E10. You know, that's an early action, early adoption. We can zip to E10, no problem.

Well, not quite. Refineries are not set

up to blend E10 and they won't be for a number of years. So before there could be a big movement to E10, there's going to have to be modifications at the refineries and modifications at the distribution infrastructure. So that's important to keep in mind when debates rage on over low carbon fuel standards and early implementation and what can or can't be done because at the end of the day, to quote Dave Hackett's favorite phrase -- at the end of the day, the system for gasoline distribution in California must be fungible.

That means one flavor for all and I may want to make an 8 percent ethanol blend because that's most economic for my refinery, but the system needs to be fungible. Why? Because the distribution infrastructure is fungible. It goes into the common carrier pipelines, common carrier storage. Your gasoline's mixed with other people's gasoline in the same storage tanks and if you have a problem, you want to turn to somebody else and say, hey, can you help me out, I need some gasoline, I had an unplanned outage.

Oh, I'm sorry. I've got a different flavor. You can't mix the two. So fungibility at the end of the day is the most important factor for gasoline distribution and planning considerations, refinery modifications, considerations.

So that's working to ultimately end up as a fungible system. So the industry collectively will have to decide what that is, E8, E10, but it's -- from what our analysis so far on the predicted model work is that we're going to a higher ethanol blend. That's apparent. Just a matter if it's at E8 or E10.

So there are other factors that are driving more ethanol use in California, a low carbon fuel standard, you know, reducing our dependence on petroleum products, and so it's likely we're headed in that direction.

So let's -- so -- you know, that will decrease the amount of transportation fuel products, the traditional ones. Yeah, it will. Yes, it will, but it will also increase the amount of alternative fuels coming in to the extent that they do over the water rather than over the rail for ethanol.

And you want to make sure that that infrastructure on the marine side that we're looking at has the ability to do that. So we'll also be looking at that this go around, that we didn't last time, and a new entrant to this whole debate is biofuels.

Okay. I'm making biodiesel. Well, how are you making that? Well, I'm getting palm oil from Indonesia. Well, are you flying that in here? No. It's -- on a ship. Into what infrastructure? Well, that's a good question.

So to the extent that biodiesel facilities may be constructed in California, they'll need a way of getting that fee stock if you will. If it's palm oil from a foreign country, it's over the water. If it's domestic source, it could over the rail.

Both need an adequate infrastructure and in enough time, an infrastructure can be put in place. Certainly enough time and money, you can do almost anything. So it's just we want to point out, it's another issue that needs to be considered. We probably won't have an answer because we're at the early stages I think of the whole biodiesel issue and the whole biodiesel debate, but it is something that is growing in use and we anticipate to continue doing so.

And -- but that's a lot of the AB1007 process work. We'll talk about that and I'm sure it'll be an important part of the debate on the low carbon fuel standard discussion.

So back to the question of are you guys forecasting ethanol imports. Yes, we are, and it's for traditional or low blend in gasoline. And somebody asks, well, what are you doing forecasting for ethanol prices. Well, what we do know is since California transitioned completely to ethanol in January 2004, most ethanol -- almost all the ethanol is sold on a contract basis of about six months' duration and it's seasonal. Here's your winter one. Here's your summer one.

And then you negotiate that a couple months in advance. Well, what's -- it's a straight price. No, not necessarily. What it normally is is I'll get a price. It'll be paid to a benchmark. I will pay so many cents over this benchmark. What is it. California gasoline.

Ethanol is sold for all intents and purposes at gasoline equivalent prices. I think Jim mentioned this. And we foresee that continuing into the future because that is what an ethanol producer can get in the market. It's at a gasoline value.

So gasoline prices go up, ethanol prices go up. Gasoline prices go down, ethanol prices go down. So it's a relationship contract and it will fluctuate like that.

In the spot market, you'll see prices -- last year when the rest of the U.S. phased MTBE, prices spiked to almost or maybe over in some $5 a gallon for ethanol. Those aren't contract prices. People had already set up contract prices at gasoline equivalent. That's spot prices for oh, you didn't get all your stuff for contract? Well, pull up here and pay dear price because you can get the rest but for that level. Because there was a scarcity.

Incremental demand for ethanol severely outpaced demand. The industry is growing and there's been remarkable growth in ethanol market in the United States. In the production side, we produce more ethanol than anyplace in the world now, more than Brazil, and that's going nowhere but up.

We're forecasting that we will achieve the renewable fuel standard goal of 7.5 billion gallons later this year. Not by 2012, later this year. So the growth in domestic ethanol production capacity has been remarkable in large part because the renewable fuel standard mandates, so there's been a strong reaction to that and MTBE phaseout.

So last year $5 on a spot market. This year, fire sale. Why? Capacity growth is now way outstripped demand for the renewable fuels for -- gasoline markets, California markets, and the low blend markets. So we see -- we're going to see more ethanol going to the -- into the discretionary markets, E85. Gasohol blending in conventional gasoline.

So on the spot basis, ethanol will be relatively cheap. But that doesn't mean somebody's going to get a bargain and be getting discounted ethanol for use as a refiner. Not likely.

So going forward, our assumption is that ethanol values will be equivalent to gasoline values, going forward.

Now, E85. Well, in a saturated market -- United States where all the low blends, everybody's doing E10. Okay. That's all filled up. Gasoline values. Well, now I got a whole bunch more ethanol. Well, what are we going to do with that? Well, I know, we could sell E85. That's another demand for ethanol. Okay. Sure. That could happen.

But put yourself in the position of an ethanol producer. If you can sell at gasoline values in a low blend market, that's your first choice because an E85 at the pump has to be discounted. Why? Less energy content. You won't go as far in your vehicle.

So I as a consumer won't pay gasoline E85 price. I'll pay a discounted price. And so if you're a producer of ethanol, you won't get -- selling to an E85 retailer, you can't sell at gasoline price because what are they going to do? Discount it and take a loss? No.

So there's this bit of disconnect, if you will, between the realities of what ethanol values go for and what E85 marketing would require to entice consumers to consistently buy that.

So once the low blend markets are satiated in California and then there's an opportunity to sell more ethanol at a discount and that would be from a low cost producer or even imported ethanol from a cheaper source, assuming the import tariff of 54 cents a gallon is removed or diminished over time, as we're seeing calls for recently.

But that's enough. So let's transition to pipeline. This is just a little more detailed. This is the Cal-Nev System that goes up to Las Vegas. There's two pipelines currently, one for jet fuel and one for petroleum products. It goes to McCarran Airport and then we have a pipeline that goes into Phoenix and then from the east, we have pipelines going to Tucson and on into Phoenix.

This capacity, what we refer to as the east line because it's on the east side of Arizona and this is the west line over here, California going into western Arizona.

That east line capacity has been basically static for -- I mean in proration meaning it's full, can't move anything more through it.

So Kinder Morgan recently embarked on an expansion project to increase the flow through this system and that expansion project was completed last summer, and I'll show you a slide in just a second. So I talked to this already. A hundred percent for Nevada, 60 percent for Arizona, and there are some other factors deeper into the whole pipeline issue and that is what kind of additional expansion capacity plans are there in this pipeline infrastructure.

Are there -- is there a pipeline that somebody's proposing from Texas into Las Vegas from the east? Right now, Las Vegas is only served from the west.

And, oh, is there going to be a new refinery constructed in Arizona? Well, clean fuels -- Arizona Clean Fuels has proposed -- they have a permit to construct and now it's just looking for a little bit of capital to build the facility and a crude oil pipeline to feed the facility.

So that's a possibility and that will certainly impact our forecast outlook for transportation fuels.

This is only meant to illustrate the impact of the expansion project being complete on that east line. The dark blue line is weekly shipments of gasoline from El Paso to Phoenix and the orange line is weekly shipments from the west side -- from California refineries to Phoenix from the west and about right here is when the expansion was completed and low and behold, the east line volumes jump up and the west line volumes jump down at commensurate weekly volume.

That just tells us that the economics and the supply logistics and the marketing plans all are such that they -- it wanted to go that direction and it did. So what does this mean?

Well, that means that a little bit of pressure's been taken off on the west side. Less volume coming from California refineries is good for California supply. Why? Because the components used to make Arizona gasoline are in many ways the same components refineries can use to make California gasoline.

Once again, being a California refinery doesn't mean you're -- for California. You're a refinery doing business in California and your market is wherever that may be, primarily California but also there's contractual obligations in Nevada and Arizona and so it's a reasonable market perspective and they supply this most economically as they can, what makes more sense.

So the market did shift. Now, you say,

well, did they change their minds and we're going to go back to the way we were. We didn't like the change.

Well, no. There was a fire in west Texas, Valero and McKee in a propane deasphalter that caused the facility to go down. And I think it's come back up now. So this just shows that it reverted close to what it was after that incident because obviously that refinery isn't supplying all of the product to Arizona.

So what our assumptions are, current pipeline capacities, pipeline capacity expansions are important to the debate on how much incremental imports will be caused by this increased demand. And so we're looking for import -- excuse me -- input from people like Kinder Morgan on this subject because they study it quite closely.

So this chart is only meant to illustrate various factors that cause our imports to be on the low side as well as on the high side, and the main ones we're going to be looking -- California demand, you know, we'll get Jim's I guess preliminary demand estimate in June sometime and we're going to be taking a closer look at processing and capacity, those refinery expansion projects I mentioned, and the whole pipeline export issue with regard to capacity.

Now, additional factors -- and I think I ticked off a couple of these -- is a new Arizona refinery. If it's completed, that will reduce our demand forecasts for imports. So that's why it's the low side and it's canceled or never gets built in the time horizon and so we go in the high case.

Low carbon fuel standard, we know that that debate will continue for 18 months if not longer. It's a very complex issue. Strong opinions on many sides of the debate. And so what will come out of that is a big unknown, a great deal of uncertainty, but we can look at some additional sensitivities if you will from our main forecast and we can say, oh, well, gosh, if we do go to, you know, E20, what does that do? The imports.

And so obviously the imports of alternative fuels will increase rather dramatically and imports of transportation fuels will decline from our baseline forecast.

So these are the -- this is sort of our game plan -- a map of the game plan and where we're planning to go, but the lion's share of the analysis will fall in these bottom three areas.

This is -- I'm telling you what we're going to do, but what we're going to actually culminate in is a regional -- here's incremental volume coming through Northern and Southern California. And oh, by the way, here's how much additional storage tank capacity you have to construct in both Northern and Southern California to offload the vessels and -- because once again, they're like a taxi. They're not going to sit there and wait till you have room in the storage tank to offload. They want to offload as soon as they tie up and then get out of here.

And we will be conducting a survey like with crude oil for crude oil throughput capacity. We'll do this for transportation fuel import -- throughput capacity and what spare capacity they may have.

And the last bullet, well, what does this mean? You must work for the Government because I don't understand what that is.

This is the -- sort of the connection between the marine tanks and getting it to those distribution terminals. Those distribution terminals are fed by pipelines -- a network of pipelines, but you have to get to the main juncture, the main pump station.

So even if I have petroleum products that I've offloaded and they're sitting in my marine terminal storage tanks and then, oh, there's a price spike. I want to get that product to market. Well, if that pipeline segment is full, get in line. It's prorated. I'm sorry, other guys are using it. Then that product doesn't get to the marketplace and so the price spike is not abated as it would have been otherwise.

So we understand that these bottlenecks have gotten a little worse and we will be including this additional analysis in our work because there is concern. It's great somebody's building additional storage tanks to meet forecasted growth in imports, but if the pipeline system can't handle that, then there's an issue.

So we're going to attempt to identify to the greatest extent possible these kinds of bottlenecks.

Why care about infrastructure, petroleum infrastructure or transportation fuel infrastructure is more accurate, California, $1.5 trillion economic engine. That's pretty big.

Goods movement is huge and we're a big portal to the U.S. goods movements. They need fuels for all that.

So we think that fuels -- we think the ability of adequate fuel supply is pretty important. And that's why any loss of an existing petroleum infrastructure -- and others have spoken to this and others may mention this today -- here today -- is a lot of the existing infrastructure is under duress, meaning others want the infrastructure removed because there's another type of commerce they want to conduct at that location.

And I'll have a couple slides on that, but that would -- I mean our assumption at this point for our forecast -- and we'll take input on this -- is we assume the existing infrastructure for importing is maintained, that it doesn't get closed down.

So change that assumption and my expansion -- and the infrastructure itself, new infrastructure, would be even greater. So it is important and we do want to keep an eye on that.

So let's talk about how would one -- you know, so we're claiming the infrastructure is tight -- constrained and even more constrained as time's been going by. Well, how do you quantify that? Well, one approach is to look at our prices and how are they different from the U.S. price for gasoline. And so we just take in our California retail price and compare it to the U.S. retail price and subtracted one from the other. The higher one's California.

And what's that difference been? Well, about 20 cents since January 2005 -- 1995. Excuse me.

More near-term, since January '04, that's when we fully transitioned to ethanol, away from MTBE. It's been about, as Jim mentioned, 25 cents a gallon.

Most recently, since January of this year, it's -- the differential has averaged 41 cents a gallon. That's a lot more than it's been.

So you get the point here. It's been increasing over time. That's right. So why exactly? Well, that's certainly not the $64,000 question. It's the $2.4 billion question.

Yes. Just so -- inability to get petroleum products here when they need to be here, as fast as they can be. You know, we maintain -- technical staff maintains that California is an isolated market. It's isolated by time and distance from next alternative source of resupply.

So you don't -- it's not electrons. It's not instantaneous on the line. This is okay, pick up the phone, find somebody who has supply outside of California. It's weeks. It's weeks away.

So if it's a bad unplanned outage, you're going to see a strong reaction in the wholesale markets. We've seen price spikes in the wholesale market of excess of 50 cents a gallon.

So translating some of that through to -- in all the products, diesel, jet, you know, you look at some large -- 25 cents a gallon is $6 billion a year in incremental costs, disposable income of California citizens, and cost of business.

So it's rather significant and important. So this is the graph of the comparison, the differential if you will between California and the U.S. and just drawing some average lines through different periods of when we were using MTBE. You know, phase two -- gasoline. This is the one year I guess transition away from MTBE for part of the industry and that's when the industry attempted to have a couple of different flavors in commerce in that distribution infrastructure.

And as you can see, that was quite a difference in the difference between California and the U.S. that it jumped up quite a bit but came back down once the industry went to a fungible gasoline.

So that's why we harp on fungible, fungible, fungible is important to gasoline supply and distribution. It's very important.

But now, I mean we're up here about 40 cents, but it's early on and we've had a tremendous amount of maintenance, unplanned outages, other problems in California that we believe are the cause of our recent price spike and we expect the market to react to new supply coming back online in California.

So -- now go back down. Couple slides real quick on that whole container versus infrastructure. 41 percent of all the containerized goods imported to the United States of America came through the two ports of LA and Long beach in 2005. That's significant and it's continued to grow.

So that needs infrastructure, rail, trucks, fuel, and land. Where the containers are stacked, where they unload it because that ship like the crude tanker is a taxi with the meter running. They want to unload that efficiently and get that container -- vessel out of there.

So strong, strong growth, 8 to 10 percent per year by the ports of LA and Long Beach. So this trend will continue, so the demand for spare capacity to build for -- is growing, growing, growing and continues to grow.

It's -- essentially the point there is really no spare land to do additional petroleum infrastructure if you will. They're going to have do what they did before. Build new land. Pier 400 in Southern California was all filled in. Now it's going to have to be something like a Pier 500, not -- there's been some sort of preparation for something like that and some infill in the bay making it more shallow, so that's something that could occur, but people are looking at them to create land rather than looking at, oh, there's a spot over there. I'll use that. Doesn't really exist.

So the pressure has come from multiple points, local politicians and members of the community and even port officials because this whole container competition.

So we want to make sure that there's multiple use in the ports. That's what the ports are for. That's the doctrine under the Coastal Commission general plan and they have to operate under that doctrine.

So there needs to be infrastructure for both types of commerce -- that primary commerce.

MR. GEESMAN: Gordon, I think in one of the reports we did in the 2005 IEPR cycle, there was an effort to quantify pollution impacts comparing container shipping and petroleum-related maritime facilities. Is there any intent to update that calculation?

MR. SCHREMP: We would be happy to include that information in this cycle. We did some additional analysis after that previous IEPR cycle in 2005. We did find that, as others have found, that additional emissions from marine vessels were growing because of -- but it was primarily containerized marine vessels, cruise ship lines.

Those were the larger component of not only the existing source if you were to create a pie chart. The petroleum product tanks were a very small component and we can get the numbers for you. I don't have them off the top of my head.

And then since that time, I think others have done forecasts, but if you look at those growth rates for -- container business, 8 to 10 percent growth per year, that certainly is stronger growth rate in the number of vessel calls for petroleum product vessels.

So even moving forward, one can say that as a share of total emissions that -- that the contribution from -- tankers and crude tankers will actually shrink relative to the total emissions from marine vessels. There are extensive efforts underway to reduce the emissions -- at the ports, using a different -- lower sulfur fuels when you get near shore and so there's lots of efforts underway.

But we believe no matter how you look at it that the share from those vessels is going to be a smaller -- is a smaller component and is going to be a shrinkingly smaller component of the total pot moving forward.

But we would be happy to include that information in the cycle.

MR. GEESMAN: Yeah. I think it's important to keep a focus on that particular perspective. I think it's potentially of benefit to both local communities and local politicians in evaluating how the ports should be used and if we can update that information and allow it to be publicly vetted by the air quality agencies and others I think we'd be performing a service.

MR. SCHREMP: Okay. Well, I think I've kept people -- you have this as your material. All this is just sort of highlights of the points I've already made and I'd be happy to take any questions at this time, unless you're really, really hungry. You can think about it over lunch.

MR. GEESMAN: Why don't we come back at 1:45.

(Off record)

MR. PAGE: Our first outside presenter today will be David Wright from Plains All

American Pipeline.

MR. WRIGHT: Good afternoon. Thank you for the opportunity to talk to you about what we think is a very serious problem, one that all Californians should be very concerned about.

First of all, I would like to introduce myself. I'm a Vice President with Plains All American and actually I'm one of the members of the predecessor company, Pacific Energy, that has made several presentations to this group.

Today I'll be speaking on behalf of the Plains All American, L.P., which is a master limited partnership, headquartered in Houston. Plains operates crude oil pipelines, crude oil marine terminals, product systems throughout the U.S. and a number of places in Canada.

And we have been following the energy situation in Southern California for many, many years. I personally have been involved with operations in the Port of Los Angeles since 1970, so it kind of puts me in the Sporano bracket of being around for quite a while. So anytime Joe's not here, we like to get a cheap shot in because we know he'll do the same.

I do work out of the Long Beach office

and have direct responsibility for the development of a deep water marine terminal in the Port of Los Angeles, project that we've been working on for several years that I'll talk about.

I'm here just to focus on a couple of points and one is the serious lack of petroleum import infrastructure in general. We also operate -- Plains also operates two petroleum products terminals up in the Bay Area and we have similar problems in terms of trying to expand and grow those facilities to be able to receive petroleum product import.

One of the main concerns though is just the extraordinary delays in permitting any of these kind of projects that we've run into and I think it's a matter of public policy that really has to be addressed. It's just become almost unworkable.

I also would like to comment on just the general condition of many of the existing petroleum infrastructure port facilities today. This is just a little follow-up on some of the work that the State Lands Facilities Inspection Division has found out through their -- reviews.

I'll give you the short version of that

I agree with a lot of what Gordon says, but probably in a more extreme case. There's no question California's domestic crude is declining rapidly. This is -- and the demand for that petroleum is growing very rapidly along with population and just the need for petroleum in a lot of our daily activities.

We tend to be more focused on the free market and less on evaluating different alternative energies. We believe that in general people are going to go to the most economic case and I think that that will be the case in amongst all the fuels that whatever fuel is going to provide the best economic use for the individual consumer is where you're ultimately going to go.

And that's why we feel that alternative energies are important. We think that a lot of the studies and efforts that are underway in the area of alternative energy are important. These are things that do need to be followed, but unfortunately, they are not going to keep up with the growing demand in California.

The other situation, whether you look at crude oil or products imports, the facilities in the California area are pretty well maxed out and

I applaud the intention of the Commission to study the existing facilities and interview the operators and look into that because I think you will we're right on the very ragged edge, particularly in the crude oil import capabilities.

The other issue that I'll talk a little bit about today is just the difficulty in permitting a new import facility. It's a very complex and time-consuming process. There's many different parties that are involved directly and indirectly. Many, many different groups that have to be addressed as you work through a process like that and the existing system with the way CEQA and NEPA is being administered in California just is not working the way it was originally planned.

It's being manipulated and used to delay major projects. The one issue that we are particularly concerned about because we see it every day, we operate two pipelines that bring crude oil from the San Joaquin Valley into the Los Angeles Basin. We also operate a facility in Long Beach where we import crude oil across Shell's existing dock and we see our pipelines coming south are rapidly declining in volume and the import needs on the facility that we operate in Long Beach are picking up very dramatically.

And we also concur with one of the statements that's on some of the materials that was passed out that you have a facility like Berth 121 in Long Beach which is owned and operated by BP and ConocoPhillips that's moving approximately a third of the oil that's coming into the Los Angeles Basin or meeting a third of the demand.

If anything happens to a facility like that, it's going to be a major economic super problem in the Los Angeles Basin throughout California.

Also I want to give you a little update about our project and just give you a general feeling of where we are and where we think we are.

This just summarizes our project. We're trying to utilize the very southern tip of Pier 400 which is a land mass in the Port of Los Angeles. It has 81 feet of water depth which is unheard of anywhere else on the West Coast.

This water depth allows you to bring in a VLCC or a very large crude carrier that can haul up to in excess of a couple million barrels of cargo as opposed to some of the smaller ships that come in with half a million to a million barrels.

It's much more efficient. We are planning permit to roughly 250,000 barrels a day. A point that not many people are aware of is that -- and this relates to a comment you made, Commissioner, about what the environmental impact from an emission standpoint -- anybody developing a berth of this nature in the Los Angeles -- in the -- area in Southern California has to offset the emissions generated from that facility by 120 percent.

So we've been working on this project for about six years now. We've gone into the market and acquired the emission credits to offset what we needed for this particular level of operation. It's been quite an interesting experience in itself.

For example, when we first started acquiring NOX for offsets, we were paying $8,000 a pound. The last ones purchased were on the order of $100,000 a pounds. These emission credits are literally just not available, or if they are, you're going to pay very, very extraordinary high price.

And anyone associated with these kind of operations realizes there's a lot of NOX, SOX, and PM that are associated with them. So this is one of the issues that anyone developing or redeveloping existing facilities is going to have to meet and address and that is the offset requirement from -- Air Quality.

The facility we're talking about building, we're designing to meet a 325,000 deadweight ton vessel, which depending on the weight of the crude can haul over 2 million barrels of cargo. We are installing 4 million barrels of drain dry storage.

The reason I mention drain dry, because of the lack of land in the port area, it's extremely important to have tankage that's very flexible so that you can bring in one kind of crude and then right behind it, take that crude completely out of that storage tank and put it in a different kind of crude.

These kind of technologies are going to be things that are important in the future and as people readdress the changing crude supply situation. This facility would offload up to 100,000 barrels an hour where some of the conventional terminals today are probably at the order of 30- or 40,000 barrels an hour.

So it's much more efficient. You can the ship in, offload a full cargo, in less than 24 hours, the ship is on its way.

This will be the most environmentally friendly petroleum terminal in the world. I know that's a big statement, but having gotten beat up by the port and people that want to mitigate this project for five years now, I can assure you it will be very environmentally friendly.

And this is an important point. We do think that this project is much better than the alternative of doing no project and it's because it will have some very serious and important mitigations that we will plan to employ and meet.

It not only impacts us, but it impacts our customers. We're not the owner of the crude. We're just an operator of a facility. So these mitigations are things that we pass on to our customers that are going to be things like the requirements for low sulfur fuels in the ship's generators, in the ship's boilers, in the ship's main engines -- where it's appropriate, where we would actually plug the ship in for at least offsetting certain portion of the emissions coming off the ships while they're at dock, and many, many other issues like that that we're working through with the port as far as environmental issues.

Another point is that when you try to build anything in California these days, you will be building with union labor. That has an impact on the cost, but it's an important aspect of the project.

And of course things that in the past used to be the primary things we worried about are still very important and that's safety and security. We have to address the issues of oil spills and potential problems with tankers and also the homeland security issues are of paramount concern and many of these factors have been built into our project.

This just gives you a visual of what it would look like. The actual berth itself is on the very southern tip of Pier 400 and the very first place that you bring a ship in.

Pier 400 itself was built about ten years ago. It's a landfill. It was designed specifically to bring crude oil in and that's been one of our frustrations is here's a facility that was designed, built, and originally justified on the basis of using the import facilities, and we've -- or import crude oil and we've been wrestling with this project for over six years now trying to get it built.

Then off to the right in this diagram, the project tanks would actually be back on a portion of the Port of Los Angeles referred to as Terminal Island. The bulk of the tankage would be in there.

Also out at the Berth 48 or the 408, we would actually have offshore side pumps which help to lower the emission load off the ship. Just another one of the environmental issues that we deal with. Unfortunately, that adds about $50 million to the project.

The project itself you see here in the chartreuse in the very lower portion of the diagram interconnects with existing pipelines, so there's really very little impact on the local community in that the whole project is built on the Port of Los Angeles and then interconnects with existing pipelines that are already in place that service all these Southern California refineries.

What are the issues that are remaining -- milestones to our entitlement for being able to build the facility? We need to get the Port of Los Angeles to issue the draft environmental impact statement and go through that process.

Then we need to obtain the Corps of Engineers' approval from the NEPA standpoint, obtain the Harbor Commission's approval from the land-lease agreement, the CEQA standpoint, and the California Coastal Commission viewpoint. Then it has to go through the Los Angeles City Hall, goes through the mayor's office for administrative review, and then on to the city council for I think their transportation and commerce committee will review it, then it would go on to the city council for final approval.

And at the same time, we have to obtain a permit to construct from the South Coast Air Quality Management District. We're well along with the AQMD. We're nearly done with all the work we need to do with them. The issues remain with the port and the city of Los Angeles.

This just gives you a little bit of the

history of the project. We originally had our initial conversations with the port actually in December of 2001. We filed an application with the port February of 2003. They accepted the application by the end of that year.

They had a scoping notice in June 2004 and a public meeting in July of 2004. Normally the CEQA process would have gone forward from that in about an eight-to-nine-month period. We're going on three years.

So the project has been literally on hold for at least two extra years while issues of public policy have been sorted out with the city and the Port of Los Angeles.

Our current status, no draft EIRs yet to be issued. After the draft is issued, we have another nine-to-ten-month period if things went well to go through the process I described. Then we estimate, you know, almost two years to get everything constructed.

So we're hopeful that we will have the facility operational by 2010. Why is that important? That's a long time from now. And when you look at some of these supply and demand charts, we're going to be already deeply into some of the problems by then.

I do want to talk a little bit about the supply and demand, at least from our perspective. We've used a firm from Dallas, Baker and O'Brien. These people specialize in petroleum studies. In particular, they specialize on reviewing refineries and refinery configurations.

They're very knowledgeable to California and West Coast refinery situations and familiar with what's likely to be done with the refineries and they understand the sophisticated nature of what today's refinery needs to change crude supplies and so forth.

One of the things they've concluded is we're going to need to import twice as much oil by 2015 than we do today. This is just Southern California and most of the comments I'm going to make are about Southern California even though it's applicable for all of California.

The current situation, the BP/ConocoPhillips Berth, Berth 121, is basically maxed out. You know, they have emission caps they deal with. They also are literally pushing the berth to its maximum capacity in terms of number of vessels.

The Shell, soon to be Tesoro, Berth is nearly maxed out. We're not quite sure how much capacity they have there because that berth is used not only for crude oil imports, gas oil, and other feed stocks, but it's also used by the refinery for other purposes of export and import of different refinery feed stocks and blend stocks.

ExxonMobil's Berth over the Port of Los Angeles is effectively out of service right now. It's an issue with the condition and age of the berth. It's like to be fixed, but I'm not sure when, but it's very limited in its capacity to move crude oil.

Then the other major facility in Southern California is Chevron-El Segundo, which is a private facility that services just the Chevron refinery. It's actually an offshore facility. It has depth limitations and what they move in and out of that facility.

This just kind of summarizes some of the things that are in the Baker and O'Brien report which we will give your -- the Commission a full copy of after it gets finalized. But in terms of today's discussion, what I would say is that this is based on just very recent information.

We just had this updated, got a copy about a week ago. They did have a number of discussions with the producers in Alaska. There's concern that not a lot will be happening in Alaska as a result of -- potential new projects, so they see the Alaskan production continuing to decline at about 3 percent per year and they expect that most of that Alaskan oil is going to be diverted, you know, to closer ports in Puget Sound and into the Bay Area.

And if you look at the fleets that's servicing -- the Alaskan fleet with a combination of ConocoPhillips and BP controlled vessels, they're really designed to supply that Puget Sound refining center and the Bay Area more than the Los Angeles area.

It's easier to supply Los Angeles with other types of ships.

Now from our standpoint, we think that the decline in California production is going to be a lot closer to the 3 percent rather than the 2 percent -- the smaller, lower numbers that in the Commission's study. And we believe this for several reasons.

If you look at say the last 10 years instead of the last 20 years, you'll see that that decline rate is really closer to 3 percent and the fact that these people are -- the California producers are extremely heavily incented today with these crude prices to produce everything they can, they would be producing at an absolute maximum allowance which we feel they are, we're still seeing a 3 and a half percent decline.

So we feel that the decline is much more likely to be in the 3 to 3 and a half percent range. You know, we agree with the 40/60 split in terms of where the Central San Joaquin Valley production's going to go.

I mean the first production will go to satisfy the ConocoPhillips refinery in Santa Maria and then the Bakersfield refineries. Then after that, and at least in today's standards, about 60 percent goes north and 40 percent goes south. But as time goes on, that relative percentage coming south is going to get much smaller and on a relative basis, there will be a higher percentage going north.

We also believe that your refinery creep number is a little low, even on its high range.

We think it's going to be more in the range of 1 and a half -- or 1 and a quarter percent and we feel this primarily because of the incredible incentive there is to manufacture and produce petroleum products in California.

It's just a matter of whether or not these refineries can be permitted to go forward. And I have several slides that I just selected from some of the information they gave us -- Baker and O'Brien gave us. This is --

MR. GEESMAN: Dave, let me ask you why you see the San Joaquin split changing over time.

MR. WRIGHT: I've got a slide that will show you that in just a second.

MR. GEESMAN: Okay.

MR. WRIGHT: And it's pretty -- it has to do a lot with what Gordon was talking about as far as the import capabilities up in the bar. They're pretty limited.

MR. GEESMAN: I'll wait.

MR. WRIGHT: This is just taking a snapshot of our projection of what's going to happen in California through the year 2021. You can see that the disposition of the California production. The Bakersfield area will stay around

100,000 barrels a day.

The amount of crude going north would stay fairly constant, but the amount of crude going south drops pretty dramatically. So this puts a lot of pressure on the import needs in Southern California.

This just looks at the whole Southern California supply picture when you factor in the reduction and domestic supply and then the relatively rapid decline in Alaskan supply that will come to the Southern California area. You can see that within the next seven or eight years we fully anticipate that the Alaskan crude's going to disappear in the LA Basin.

Now, why is that important? It gets back to several other things that Gordon was talking about. It changes the type and nature of the supply.

The Alaskan fleet was designed to run the Alaskan crude that runs seven or eight days to get oil from the Prince -- or from Valdez on down into LA and then the ships turn around and go right back.

They're relatively steady. The cargoes are on the order of about, oh, upwards of -- well, they've got a number of 125,000 deadweight ton vessels which are on the order of about a million barrels now. So they're very ratable. They're almost like a pipeline in a sense.

Also the tankage that's needed to receive that crude is designed specifically to receive that crude so that they have a homogeneous pool of Alaskan crude. Now, as the Alaskan crude disappears, it's going to be replaced by crudes from all over the world. So all of a sudden, your supply line instead of being seven days or eight days, it could be 30 or 40 days.

So you have a lot of variables that could impact that supply line. You're also going to be bringing more different types of crude so that the types and the amounts of tankage that you're going to need are going to change. For example, instead of needing to store a million barrels of the same kind of crude, you could be bringing 2 million barrels of three or four different kinds of crude.

So all of a sudden you have to have a much bigger amount of marine receipt tankage to take that cargo in.

In addition, at the same time as that

California production declines, instead of having a ratable supply of crude that comes in on a pipeline that you can handle at a refinery with a very minimal amount of tankage, you're all of a sudden going to replace that with a supply that's going to be much less ratable and it could come in big shots.

You know, if a ship has a problem, has to slow up, then you're going to be potentially running short on crude, so you'll tend to have more crude on hand. If the refinery has a problem, all of a sudden the ship gets backed up because they're not going to need the crude, but it's on a 40-day voyage. You can't just turn it off.

The other issue, Gordon said that, you know, the demerge (ph) on the ships is about 50,000. Well, it's more like a $110,000 a day. So it becomes a very complex economic situation to, you know, on these larger ships of how you're going to deal with the demerge issues.

Also just as a rule of thumb, in our operation -- and I've been around marine operations for many, many years, we feel that whenever you have a dock that's over 65 or

70 percent utilization that you're starting to max out the effective capacity of that berth in terms of the optimal amount of demerge and ship traffic that you can handle on it.

So as you get in a higher percentage, you're going to run more demerge and it's not necessary economic. So that's kind of rule of thing that we look at. If we see a 70 percentage utilization particularly on long-haul crudes, then we start thinking that we're starting into a situation that is less than desirable.

This just looks at the -- where's the Southern California crude going to come from. On this slide where we say Latin America, we're really talking about South America, Latin America, and Mexico. So these are basically any oil south of the U.S. and historically there's been quite a lot of Mexican and Ecuadorian crudes that have come into the U.S.

Unfortunately, Mexico's got their own serious problems. From being a major exporter, you know, we're seeing projections that they may be an importer relatively soon because of mismanagement of their own oil production.

The Ecuadorian situation has changed

quite a lot from a political standpoint. Some of the major oil companies like Occidental have been asked to leave. The local government there is now starting to try to take over some of the production. We envision that that is going to be less efficient and less more secure as a supply source.

So this going to put more and more pressure on bringing oil from places all over the world, you know, west Africa, Canadian exports that will come to Southern California, and in particular the Middle East. So you're starting to look at the 30- and 40-day supply lines.

This just looks at the incremental foreign imports coming into California. It's taking just a snapshot of the last diagram, but you can see how quickly the need for this facility is going to build up. So by 2010, you know, we're projecting -- we -- we're looking at a 250,000 barrel a day import facility. We're going to almost be there by the time this terminal is built.

So I'm not sure what's going to happen in 2008 and 2009. I'm not sure how that oil is going to ultimately get into this market. But you can see after that the demand for imports are going to increase very rapidly.

One area I mentioned that I was going to talk about a little bit and this is just the condition of the existing facilities. I don't want to take any of the thunder from State Lands facilities people. Kevin Mercer's here today and Kevin and his -- the group that he works with have been heavily involved in this.

There's been some articles and a number of reports published, but this is a very, very touchy situation we have.

When you look at, for example, Berth 121 is the newest berth in California. In 1970 -- it was built in 1979. So it's almost 30 years old. On average, the average age of the wharfs and piers in California is over 50 years.

A number of the ones that I used to work with when I was with Conoco and JTX and Tosco were old wooden piers that were built -- some of them built before or right after World War I. Others were built during World War II.

The port, you know, was supposed to maintain these. Well, they didn't really maintain them. Many of them are not designed for the kind of vessels that are coming into the facilities today. The vessels are much larger. There are many, many other considerations that people take into consideration today. They didn't when the facilities were designed in terms of the amount of load that a ship puts on the dock when it's docked, the amount of, you know, stress that a dock can take in an earthquake or a tsunami situation.

There really are -- there's an awful lot of facility work that needs to be done on these facilities and I think that's one of the elements that needs to be factored in in your study as you go forward. You know, what condition are all these facilities in and how much work and effort's going to need to go in to changing the infrastructure and improving it and at the same time, how are we going to get, you know, the CEQA work and the other stakeholder issues addressed as all this work's being done.

So I think one of the areas that needs to be focused on is really the public policy, how we could change the attitude to recognize that, yes, all the stakeholders need to be addressed, environmentalists, the industrialists, the cities, the ports, et cetera, but we have to come up with public policy that will speed this process up and let the people that need to get this work done address the issues but get it done. So that's one of my main comments.

Anyway, that's the end of my prepared comments. I would comment on a number of things that Gordon said in his comments that, you know, we're dealing with very, very complex situations. They respond a lot to economic situations.

As you force major changes into the system, it takes a lot of physical work to adapt the systems. So really the industry needs to be given a solid planning platform and an environment to work from to make these adjustments and meet the changes that California's going to need to meet.

So I appreciate the opportunity to speak to you and that's my comments.

MR. GEESMAN: Thanks for coming. I think that this is the third time that you have graced us with your presence at one of our Integrated Energy Policy Report hearings.

I'd have to say that we've been unsuccessful in a number of different areas with policies we've tried to promote, but there's probably no single area where our lack of success has been more glaring than in our inability to call attention to the state's and in particular Southern California's petroleum infrastructure.

And I -- we continue to try and figure out new ways in which to do that. Open to any suggestions you or others may have, but it is a hole that we have dug for ourselves in many ways and it's a deeper hole than it was five years ago when I started coming to these hearings.

MR. WRIGHT: Thank you.

MR. PAGE: Our next speaker will be Jeremy Cuisimano of the Department of Energy.

MR. CUISIMANO: Thank you. Thank you for having me here today. I'm glad I could come out and talk to you all.

As Jim said, my name's Jeremy Cuisimano. I'm the Chief Economist for the Office of Petroleum Reserves at the Department of Energy.

The purpose for me being here today is to first share a little information on what we're doing on the strategic petroleum reserve. Our -- we're currently about to get underway with an expansion to 1 billion barrels of storage capacity, but then also to get some information from everybody else who's presenting here on the projections for the California energy markets.

A little background on the SPR. We were authorized in 1975 in the Energy Policy and Conservation Act. Primary mission is U.S. energy security as it pertains to liquid fuel supply and also supporting the International Energy Program and our participation with the International Energy Agency.

Current configuration consists of four storage sites all along the U.S. Gulf Coast. All the storage takes place in salt caverns underground and we currently have a storage capacity of 727 million barrels.

Our inventory is -- we're currently adding some oil at the moment, so our inventory is somewhere around 690 million barrels and we have a draw-down rate of 4.42 million barrels per day.

Our authorizing legislation authorized the reserve up to a billion barrels. The Energy Policy Act of 2005 gave the Department of Energy direction to expand to that billion barrels from our current authorized capacity of 700 million barrels.

This is a diagram of the current SPR sites and where they lie in relation to some of the Gulf Coast infrastructure. Two sites in Louisiana, two in Texas.

The sites that are highlighted in yellow are where the expansion to a billion barrels is going to take place and they'll involve acquisition of new property at Big Hill in Texas which is near Beaumont, Texas, and development of new caverns there. In Louisiana, the Bayou Choctaw site which is currently our only site that services the Capline System and the lower Mississippi River refinery system.

We're going to add a couple caverns there and we are going to develop an entirely new site in Richton, Mississippi, which will have connections to Pascagoula, Chevron's refinery there, as well as the Capline System. I believe it's Liberty Station where it will connect to the Capline.

In President Bush's State of Union Address this year, he announced that we will expand to a billion and a half barrels. Our current discussions up until that point had been only to a billion barrels. But the increase need for -- to deal with national security issues and recognition of our declining import protection which is a responsibility under the International Energy Program through IEA Treaty, we're required to stockpile 90 days of net imports. That includes industry stocks, but that number, it's becoming more clear that the number that we've been counting as industry stocks to meet that requirement, significant portions of those barrels would not be available in the event of an emergency because they're required for minimum operating quantities within our pipelines and refineries and tanks and such.

So while we have clear engineering plans and designs to go to a billion barrels, we don't really have a clear plan for that next 500 million barrels. So part of what we're doing now and part of the reason why I'm here is that we're -- have undertaken a broad vulnerability study nationwide of fuel supply, infrastructure, refining, and all the related issues.

This is a chart that just shows the different scenarios of our 90 day net import requirement within the SPR. The -- going out to the right there, the orange bars are the SPR in its current size. The green bars on top of that take into account the expansion to a billion barrels and it would ultimately require this expansion to a billion and a half barrels to get above that 90-day net import requirement.

MR. GEESMAN: Do you ever conduct that analysis on a regional basis?

MR. CUISIMANO: No, we haven't. And we're -- part of this vulnerability study is -- well, actually all of it is regional. The West Coast -- as you know is disconnected from the rest of the nation's oil supply system and so that's one of the things that we're taking a close look at are regional vulnerabilities rather than at a national level which we've done up until this point.

MR. GEESMAN: You know, in 1975 when the Act passed, we were assured here in California we didn't have to worry. We had Elk Hills. The Government chose to privatize Elk Hills sometime in the 1980s. I would suggest your vulnerability assessment is a couple of decades late, but certainly welcome.

MR. CUISIMANO: Well, you know, as far as the sale of Elk Hills goes, that was actually before I joined the department, but there are still people around there that are, you know, kind of kicking themselves, you know, wondering why that actually happened. But for whatever the reason was, it happened nonetheless.

MR. GEESMAN: A pretty large part of the country -- a pretty large part of the economy left out here hanging and certainly all of the discussion about security concerns may resonate nationally, but I think that the blindness that has been turned to the West Coast in the Pad 5 region is something that the Congress and the President ought to do something about sooner rather than later.

MR. CUISIMANO: Point well taken. This chart here is just another one of the I guess justifications for this -- our expansion. We had to do a fairly thorough economic analysis of expanding and it was -- study -- number of these have been done, but essentially looks at two different worlds, one world where you have a larger strategic petroleum reserve and the current situation.

And -- based on risk assessments which these two lines are, represent two different assessments of risks to oil supply and based on those risk assessments, through a simulation model, it calculates loss of voidance by having a larger strategic petroleum reserve.

The point of this is that it showed increasing net benefits out to and beyond 1.5 billion barrels.

So as I said, we don't have any set plans yet for that extra 500 million barrels. This shows a crude timeline of current expansion plans which involve expanding the capacity at our current sites and developing the new site in Mississippi. The goal that's been set for expansion is to reach 1.5 billion barrels by 2027.

So this vulnerability study that we've been given clean slate by our management and they've said, you know, look at everything and so we're starting and we're looking at just the basic data of import, consumption, and all the projections, but trying to answer the question of what do we want to store, is it crude oil, what kind of crude oil. Is it some kind of refined product, where should it be stored, and what should the storage mechanism be.

We're currently storing all of our

product in salt caverns which is by far the cheapest way to store any kind of product, crude or refined petroleum product. If we leave the Gulf Coast area, the opportunities to store crude or product in that fashion decline significantly.

And we're also looking at additional types of vulnerabilities. We're traditionally focused on strategic vulnerabilities which would be things like foreign -- disruption of foreign imports for political or other reasons, but as we saw with Hurricane Katrina, we have some vulnerabilities in our distribution infrastructure from natural disasters.

The Alaskan production, when they had to shut down the pipeline up there, that was another example of a nonstrategic disruption. And as we're seeing the State of California has some infrastructure issues that, although not strategic, could be very critical to the fuel supply of this area.

So some of the options that we might put forth once we've done this analysis, more storage in the Gulf with perhaps some increased distribution capability, regional storage, the East Coast -- projections for the East Coast show pretty frightening gasoline import picture. West Coast, obviously similar product issues.

You know, it wasn't that long ago that California -- as everybody's seen time and time again today, wasn't that long ago that California was pretty self-sufficient and there had always been some level of exports and imports, but they were more structural, done for convenience rather than the need. Again we'll consider some kind of refined product storage and it's also been suggested that we consider LNG storage.

So some of the things that are important to us while we're going through this, you're looking at our current distribution capability. We have the ability to distribute to Pads 1, 2, and 3 fairly easily in short periods of time. Pads 2 and 3 are well serviced by existing commercial pipeline infrastructure. Pad 1 requires barge or ship, but again the transit times are not very long, but the -- something that we've been focusing on recently is the long transit time to the West Coast.

We are -- we're required to be able to draw down and actually start delivering oil 13 days after the President gives the order to do so, but if you add that on the, you know, 13, 15, or more days of transit time to the West Coast, you're at almost a month before any physical product gets to the West Coast.

We've been talking to the Trans-Panama pipeline people. There are plans to reverse the flow of that pipeline from -- it's currently traveling from west to east. There are plans to reverse that moving east to west and there are also plans to widen the Panama Canal and we look at those as both good things that will both shorten the transit time to the West Coast for SPR crude and also help make a more integrated national distribution system.

These are just another example of what everybody's already seen today. The picture going out in the future is -- or the -- just simply one of Pad 5 and California will need to import much more crude and refined product than they currently do.

And a different look at the same issue essentially, showing the declining ANS product and the need for more foreign crude and product imports.

Now, there has been a little discussion

today about refinery creep in California and what the right side of this chart shows is this is all from EIA data, but they're forecasting a .7 percent per year growth in refining capacity in California and they're -- based on the annual energy outlook, that red line there shows what they're projecting for consumption in Pad 5. And so it won't be long before the ability to meet domestic demand here completely is surpassed a great deal by consumption.

And so what we're looking for, which I think I've gotten some today and I hope with Gordon and the other staff folks here at the CEC, to be able to get in a little more detail -- you know, some of these projections particularly relating to the infrastructure, that's not -- you know, we're Gulf Coast. People are focused on that area on the infrastructure there most of the time. There is a lot that we don't know and that we need to know about what -- the product -- distribution system here, you know, we don't have enough information on. We don't know what that's expected to look like 15, 20 years from now.

What -- you know, the same for crude oil, refining capacity, and we see those infrastructure issues as by far the biggest vulnerability issue to the State of California and therefore Pad 5.

So I thank you for having me here and I look forward to working with the CEC staff a little more and hopefully when we put out this vulnerability study, it will be something that reinforces the mission of both the U.S. DOE and the California Energy Commission.

MR. GEESMAN: When you do expect your report to be publicly available?

MR. CUISIMANO: I don't know. It -- the pace has been driven largely by data availability which to this point has been a problem. So for the Pad 5 portion of this, we may be piggybacking the work that the CEC's doing now. And there -- it is unclear to me at this point how much of this report would not be made public.

MR. GEESMAN: Yeah. I wonder if you'd expand a bit on the rationale for potentially seeing LNG storage as a way in which to meet vulnerability needs in the petroleum sector.

MR. CUISIMANO: Well, in the liquid fuel sector, there are places where -- and this is becoming less so, but places where there's fuel switching between liquid fuels -- liquid petroleum fuels and natural gas for fuel supply.

As our domestic natural gas production declines, that energy source is going to have to be replaced by something else, and if we do not develop LNG facilities for the importation of natural gas, then the most likely substitute for that natural gas would be some type of liquid fuel.

MR. GEESMAN: Thank you.

MS. BROWN: I just want to ask, so will your study make some specific recommendations about infrastructure improvements out here that, for example, might be needed to accept oil that might be tankered, you know, via water to the West Coast?

MR. CUISIMANO: We'll probably stop short of that. We will highlight any particular vulnerabilities that we see, including infrastructure, but our recommendations will be designed as potential alternatives for strategic stockpiling.

MS. BROWN: I'm not really current on the -- how SPR ius being used in the last few years. Have you learned any lessons -- key lessons from draw-down on the SPR, for example, during Hurricane Katrina? I think you mentioned that distribution being knocked out made it impossible to get the oil from the SPR to the needy areas. Have there been other examples like that where the SPR going down was, you know, to meet a physical supply shortage?

MR. CUISIMANO: That was the -- its only recent sale that's occurred where the President declared an energy emergency and a sale was conducted. Two major lessons that were learned out of that, one, that we were underprepared, I should say. I guess -- underequipped to deal with shortages in the Capline System. We only had one site and it was our smallest site serving that area, and we needed more there which our Richton, Mississippi, site will provide.

And the other was that we -- in the event of product outages as, you know, when the Colonial and Plantation Pipelines went down because of power losses, there was essentially nothing that we were prepared to do on our own to service the Northeast as they were -- their stocks of products were dwindling. That was -- that showed the importance of our association with the

International Energy Agency because we were able to sell crude oil while the Europeans sold products and the products made their way to the East Coast.

MS. BROWN: But in no case has the SPR been drawn down in a way that would benefit the West Coast. For example, during the Exxon Valdez, you know, incident where we lost quite a bit of crude --

MR. CUISIMANO: Well, yes. Well, during that --

MS. BROWN: My recollection was there was a draw-down, but I don't recall the specifics of how it worked.

MR. CUISIMANO: During that time, there was no draw-down to deal with the shortage of crude oil coming from Alaska. In the recent Alaskan crude shortage -- or when the pipelines were shutdown, the BP fields, we were continually every day talking to refiners both in Washington and California and we were prepared to take some action if it was needed, but in the end, it was determined that it was needed, that the refiners had enough crude oil and they were able to get it -- other sources of crude oil and were going to make it through without any actual shutdowns.

MS. BROWN: How would you change your strategy given what you heard from the prior speaker about the limits of marine infrastructure, for example, in Los Angeles. To me that sort of changes the whole character of the work you're doing.

MR. CUISIMANO: It does. It's -- makes me personally very concerned about the fuel supply for the state. And as far as the strategic petroleum reserve goes, we could not cite any facilities where we did not have clear access to water essentially to export -- or not export, but to transport our products to other locations or to bring in, you know, crude or product, whatever we would store. And so that would -- if we were to consider citing a facility out here, that would be -- would make it almost preventative -- not being able to do it without having the proper import facilities here.

Any other questions? Okay. Well, thank you.

MR. GEESMAN: Thanks very much.

MR. PAGE: Next up prepared comments from Gina Grey from Western States Petroleum

Association.

MS. GREY: Good afternoon, Commission Geesman and Advisors. Our president, Joe Sporano, was hoping to be here today to provide our prepared remarks. Unfortunately, his schedule changed at the last minute, but he does send his regards and I volunteered to provide the WSPA comments, which is why I'm here today. My name is Gina Grey. I am Director of Policy and Fuels for the Western States Petroleum Association which is also known as WSPA.

We do appreciate the opportunity to provide our perspective at this stage in the development of the 2007 IEPR. We'd like to congratulate the CEC on the approach that was outlined in staff's overview that was developed for this workshop. In particular, we are very encouraged by the inclusion of projections that include a range of possible scenarios from high to low for the critical areas in the report such as prices, demand, fuel, and crude oil imports.

As you may be aware, in prior workshops dealing with energy, WSPA has always been a proponent of including ranges and not just one single number to give policymakers some idea of what the bounding and I think Commissioner Geesman used the words bounding the uncertainties this morning, and we would certainly agree with that.

In addition to our testimony, we are providing you with letters, which is what I just provided you with, that we have submitted on issues that are relevant to today's discussion. They are an April 2nd letter to Brian Prusnick of the Governor's Office and a letter that was delivered yesterday to Katherine Witherspoon, Executive Officer of ARB.

Both of these letters contain important comments, recommendations, and concerns about the low carbon fuel standard. We ask that these two letters be made part of the record of these proceedings. We will also be submitting more detailed written testimony following the workshop.

All right. First, the workshop notice posed seven questions regarding fuel price and supply projections and other forward-looking information. Unfortunately as a trade association that represents commercial competitors, WSPA cannot answer the forward-looking questions nor do we believe that anyone else can answer them with any degree of surety. However, we do believe it's essential that your projections are based on sound data and reasonable assumptions and analysis.

We have expressed to you in the past our concerns about building models or basing projections on what the state would like the energy picture to be as opposed to what it will be. Policy initiatives designed to reduce petroleum consumption should not be the basis for demand projections. While we may disagree with some of these policies, we all should agree that rational planning must be based on facts and reality.

The Governor's letter to the Legislature in 2005 articulated future energy goals such as adequate, reliable, and affordable energy supplies using advanced energy technologies. We believe these are still valid and appropriate goals for the state.

Now, I'd like to spend a couple of minutes on climate change initiatives and those initiatives as they relate to energy planning. Since the Commission developed the 2005 IEPR, California has embraced an ambitious program to reduce greenhouse gas emissions by 25 percent over a roughly 13-year period. We believe it is incumbent on the Energy Commission to look at and factor into its projections the potential negative or even positive impacts that the implementation of greenhouse gas emission strategies could have on transportation and fuel supplies.

If as may be the case refineries already have implemented most of the energy efficiencies provided by current technology, there are limited ways for them to reduce their CO-2 emissions other than to reduce production. Our analysis indicated that we did previously, approximately a year go, that without break-through technologies, implementation of AB32 could result in a decline in refinery output.

Given California's population and fuel demand growth projections that we saw today, any percent decline in transportation fuel supplies could significantly impact the economy and quality of life enjoyed by California consumers and businesses.

We are currently working with the ARB, with yourselves, and the Governor's office and others to implement AB32 and the Governor's low carbon fuel standard in a manner that hopefully does not lead to reduced transportation fuel supplies. There is a critical need, however, for the CEC to broaden its focus outside the boundaries of California. And I think, Commissioner Geesman, you talked about that early today with Gordon, but we're making the same statement, slightly different context.

The list of questions prepared for this workshop all tend to focus on what will occur in California. What might be even more relevant is what will happen outside of California, both nationally and internationally. Energy markets and supply chains all work as systems. California, for example, isn't the only state wanting to reduce greenhouse gas emissions and encourage a shift to alternative and renewable fuels.

As you know, there's the West Coast -- and I'll probably not get the correct name, but there is a regional initiative dealing with greenhouse gas reduction. The state needs to ensure it includes in its demand forecast any growth in amounts of gasoline, diesel, and jet fuel products that are currently produced in California refineries or imported through California port facilities and then shipped from

California to Arizona, Nevada, and in some cases, Oregon as Gordon had mentioned.

We cannot afford to leave these volumes and these other state plans on greenhouse gas emissions out of the supply/demand analysis.

Now moving on to the low carbon fuel standard or LCFS. It is essential that the LCFS be designed and implemented in ways that will not discourage further investment in California's petroleum based fuels infrastructure. CEC projections over the next several years show a large and growing gap between gasoline and diesel demand and supply. Several real constraints impact the ability of transportation fuel suppliers to supply their California customers, and I believe previous presenters have provided you with some examples.

We have urged the creation of a step-wise implementation process where the CEC and ARB review and evaluate progress. Together these two agencies should jointly make a determination that adequate LCFS fuel supplies and infrastructure are in place to allow implementation of the next steps of the LCFS in an orderly manner and with minimal disruption to the state's transportation fuel market.

Additionally, the LCFS program should have firm, well-defined, and scheduled milestones at which the CEC and ARB review and evaluate progress and jointly make findings and determinations. Policymakers can then be alerted to the potential for disruptions in transportation fuel supplies and associated market volatility using complete transparent reports to the Governor and Legislature.

Now a third critical issue for WSPA companies is as you've been hearing many times today, ports and imports. Port infrastructure is a particular concern of ours as Gordon Schremp has so ably outlined. Two-thirds of crude oil supplies process in California refineries are imported from foreign sources or Alaska using vessels that deliver those supplies through the state's major southern and northern ports.

Gasoline imports as well as their blending components, these are required every day to meet current demand and these by and large come through our California ports.

Current public port policies are very directly impacting the entire state's energy supply balance, and WSPA believes the state needs to step in and gain control over this situation before port policies against the movement and use of petroleum-based fuels results in damage to California's economy.

Now, this may sound like a rather dramatic statement, but hopefully the statements that you heard from others today give you an idea of why we're believing that the state needs to step in and be much more active on this.

MR. GEESMAN: Yeah. Let me try and peel that back a little bit more, Gina. I don't think you're talking ports statewide. You're talking about a couple of specific ports, are you not?

MS. GREY: That's correct.

MR. GEESMAN: And would I be mistaken in guessing that the primary one is the Port of Los Angeles?

MS. GREY: You could probably guess that correct.

MR. GEESMAN: I just think that we ought to call a spade a spade.

MS. GREY: Okay. The other point I think that needs to be made too is that obviously a lot of my comments are directed at petroleum, but since the state is moving towards a lot of, you know, renewable and alternative fuels, those same port issues are going to arise for many of those types of fuels as well not just for our own products. So it's sort of all across the board.

According the CEC's 2005 IEPR, California's marine infrastructure was at or near the limits of throughput capacity and I think we heard that again today. If that infrastructure capacity does not expand, crude oil supplies, blending components could become even more constrained than they presently are.

We were encouraged in the '05 IEPR that the CEC had embraced and described many of our concerns relative to infrastructure, and I sense that the new one will as well for '07, such as the retention of existing facilities and the need for new construction, permit streamlining, port capacities, and policies, environmental justice, et cetera.

Unfortunately, there has been little if any improvement for us in two years in any of these areas.

MR. GEESMAN: Tell me if you've discerned any.

MS. GREY: I would recommend to tell you the truth in terms of specifics to that question that we would love to sit down with yourself and others in the Commission and have those types of open and frank discussions and really sit down and try and get at the meat of what may be able to be done in terms of forward action on that.

In conclusion -- I'll be brief today, we do thank you for considering our comments and we also thank you for your willingness to continue to work on a collaborative process, and as we indicated earlier, we're hoping that that collaborative process will be with yourselves, stakeholders, and ARB, so all elements, first on improving the fuel cycle analysis which we had talked about at a prior workshop; second, on developing a California-specific dynamic simulation transportation energy model; to evaluate and compare various LCFS scenarios for their economic impact -- and I believe Commission is also engaged in that -- and third, in engaging in firm, well-defined, scheduled milestones at which the CEC and ARB review and evaluate progress and jointly make findings and determinations in complete transparent reports to the Governor.

And those are our WSPA comments.

MR. GEESMAN: Thank you, Gina.

MS. GREY: Any questions? Good. Thank you.

MR. GEESMAN: I have one blue card from our old friend, Dave Hackett, Stillwater Associates.

MR. HACKETT: Hi, Mr. Geesman. Thanks very much for calling me an old friend. You know, I've been here as much as anybody else in the room has over the years, and I kind of made a list here of the projects that Stillwater has done either for the Energy Commission or for other people -- other stakeholders in this and it's kind of a long one, so I'll skip it.

Jim, would you mind putting up your presentation and finding that slide with the bar graph on refinery margins. And while Jim's doing that, I want to talk about that, and the other thing that I want to mention really quickly is that we're doing a fair amount of work in renewables these days, especially focused on biodiesel. And what we see is that right now, the feed stock to provide biodiesel in California are relatively constrained. It's primarily animal fats or waste cooking oil. There really aren't any oil seeds to speak of.

And so commercial scale biodiesel plants that have come onstream are likely going to come onstream wanting to run palm oil from Southeast Asia or South America, and the -- and so these facilities have the same constraints you've heard at least twice from Gordon and from Gina. Trying to get a tank to bring that stuff ashore and it's just hard to find. It's the same problem.

And go back to -- there's a -- you've got bar graph -- this one, yeah. I think this is really interesting and, Jim, may I borrow your -- anyway, the point I want to make is that there's a significant step change especially on gasoline and on diesel fuel and gasoline margins and the breakpoint chosen here is carb phase 3.

And if you look at those numbers at least on the gasoline side, that looks like 15 cents a gallon or more between carb phase 2 and carb phase 3 and as Gordon pointed out, that's over $2 billion a year. I don't think that when carb phase 3 was rolled out, the price tag was set at 2 billion. I don't think it was that high.

We've got another gasoline quality

change coming up. People are calling it carb base 4. ARB is saying it'll cost a penny a gallon. Well, you know, that doesn't seem to hold up in the face of these kinds of data. And so what I would suggest is that CEC staff spend some time thinking about why it is that phase 2 to phase 3 was what looks like 15 cents a gallon and as well diesel is up and you see that diesel's up.

So I can -- as analyst, I can see the supply side. I can see the refinery data that you produce and so I can see what's happened to gasoline production. I can see what's happened to gasoline -- I'm sorry -- diesel production. I don't understand the demand side very well, but I think it would be useful as part of the carb phase 4 exercise to have thought through what's happened in the past and see if that might apply to what might happen coming up with carb phase 4.

MS. BROWN: Dave, a couple of things. First you're talking about the new formulations that would fall out of the predicted model role?

MR. HACKETT: That's right.

MS. BROWN: And secondly, are you familiar with the work we're doing with MathPro?

MR. HACKETT: Yes. And --

MS. BROWN: And wouldn't that in fact give you the kind of answers you're looking for?

MR. HACKETT: Well, the MathPro exercise I expect -- and I'll defer to Gordon on this. MathPro exercise is designed to look at what it's going to cost the refineries to make the changes necessary for this new formulation and it seems that's primarily going to be lower sulfur. And so they'll do probably a pretty reasonable gas that, but as we saw with carb phase 2, you know -- or some of these other changes, I think that the refinery only part of the equation didn't pick up the impacts that we saw on the market and especially with phase 3 where the market got so -- got tight. It was again another boutique fuel.

There seemed to be more market factors in there over and above the cost of the refinery production.

MS. BROWN: That's fair.

MR. HACKETT: Thanks.

MR. GEESMAN: Thank you, Dave.

MR. PAGE: Do we have any more public comments? Failing that, I'd like to express my appreciation of all you for attending this very productive meeting, I believe. Thank you, Commissioner Geesman, for being here all day, and the next step, as Gordon mentioned, will be our July 12th workshop in Los Angeles, which we'll present our completed forecasts. Thank you.

(Whereupon, at 3:02 p.m., the IEPR Workshop was adjourned.)

--o0o--

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission IEPR Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 21st day of May, 2007.